DOD-IR-71

Sekimura Direct, p. 44.

Please provide a comparison of the estimated year-end 2006 short-term debt balance with the actual short-term debt balance, describing and detailing the differences in the amounts, if any.

HECO Response:

As presented in HECO-1902, HECO's estimate for the year-end 2006 short-term debt balance was $77,942,000 based on a projected source and use of funds for the year. The actual short-term debt balance for HECO for year-end 2006 was $58,707,000, or $19 million lower than projected due primarily to higher than estimated internal sources of funds, partly offset by lower than estimated contributions in aid of construction; therefore, reducing the need for external financing (i.e., short-term debt).

DOD-IR-72

Sekimura Direct, p. 47.

When HECO sells revenue bonds and does not use all of the proceeds for construction and the amount remaining with the trustee draws interest (i.e., there is a "net income" position), does that effect the embedded cost of debt paid by ratepayers? If so, please show how the cost of debt provided by ratepayers is adjusted to account for interest income on revenue bond funds not spent; if not, please explain why retaining interest income represents a fair balance of ratepayer and stockholder interests.

HECO Response:

Yes, the revenue bond investment differentials, i.e., the difference between the earnings and the interest costs of the undrawn proceeds in the construction fund, affects the embedded cost of debt paid by ratepayers. As discussed in testimony provided in T-19, pages 45 through 47, the long-term debt balance for the test year is net of the unamortized balances, which in turn determines the effective rate of the embedded cost of long-term debt (see HECO-1903 which shows the calculation of the embedded cost of long-term debt). The effective rate is then passed on to ratepayers through the Company's composite cost of capital. HECO-WP-1903, page 5, shows the details of the revenue bond investment differentials.

DOD-IR-73

Sekimura Direct, p. 53, l. 21.

a) Please describe in detail the "annual insurance premiums," and explain why they should be included in the embedded cost of debt.

b) Is Ms. Sekimura aware of other regulatory jurisdictions in which insurance premiums are included in the embedded cost of debt? Please provide all available support for your response.

HECO Response:

a. The annual insurance premium is for the revenue bond insurance. Bond insurance purchased by the Company obligates the bond insurer to make interest and principal payments on insured bonds in the event the Company does not make these payments. Bond insurance ensures buyers of the bond that interest and principal payments will be made, whether by the Company or by the insurer. Since the insurance assures bondholders that the insurer will pay in the event that the Company does not, insured revenue bonds receive the higher credit rating of the insurer, rather than the credit rating of HECO, thereby reducing the interest rate to be paid by the Company on the bonds.

The annual insurance premium should be included in the calculation of the embedded cost of debt because ratepayers get the benefit of the lower cost of financing (i.e. interest rate for an insured bond is lower than the interest rate for an uninsured bond), thus it is appropriate for ratepayers to pay for the cost to insure the bond.

b. No.

DOD-IR-74

Sekimura Direct, HECO-1900.

Please provide a complete copy of Ms. Sekimura's cost of capital testimony in Docket No. 05-0315.

HECO Response:

Please see pages 2 to 73 of this response for a copy of Ms. Sekimura's cost of capital testimony (Direct and Rebuttal) in Docket No. 05-0315 (HELCO's 2006 Test Year Rate Case).

HELCO T-18
DOCKET NO. 05-0315

TESTIMONY OF
TAYNE S. Y. SEKIMURA

FINANCIAL VICE PRESIDENT

HAWAII ELECTRIC LIGHT COMPANY, INC.

Subject: Rate of Return on Rate Base

HELCO T-18
DOCKET NO. 05-0315

TABLE OF CONTENTS

INTRODUCTION

Q. Please state your name and business address.

A. My name is Tayne S. Y. Sekimura and I am the Financial Vice President of Hawaii Electric Light Company, Inc. ("HELCO" or the "Company"). My business address is 900 Richards Street, Honolulu, Hawaii, 96813. HELCO-1800 provides my educational background and work experience.

Q. What is the purpose of your testimony in this proceeding?

A. The primary purpose of my testimony is to recommend a fair and reasonable rate of return on the Company's rate base for test year 2006. I will explain the basis for HELCO's capital structure and the derivation of its composite cost of capital. I will provide details supporting the Company's sources, proportions, and costs of investor funds. Further, my testimony recommends to the Commission a rate of return on common equity, based on the testimony of Dr. Roger Morin, Professor of Finance, Georgia State University, College of Business, who has developed an estimate of the return on common equity he deems to be fair and reasonable.

Another purpose of my testimony is to explain why the Company does not believe that it is necessary to conduct a comprehensive analysis for this docket of the impact of Hawaiian Electric Industries, Inc. ("HEI") on HELCO's cost of capital (in regard to D&O 15225[1]).

In addition, my testimony includes an estimate of the savings to customers resulting from the use of special purpose revenue bond financing, as required by Hawaii law.[2]

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[1] Decision and Order No. 15225, filed in Docket No. 7591 on December 10, 1996.
[2] Hawaii Revised Statues ("H.R.S.") Section 39-A-208(b).

RATE OF RETURN ON RATE BASE

Q. What is the purpose of the rate of return on rate base?

A. The rate of return on rate base is used to calculate the revenues necessary to fairly compensate investors for the use of their money invested in assets that are used or useful in providing service to the utility's customers.

Q. What is the fair rate of return on rate base for test year 2006?

A. A fair rate of return on rate base for HELCO for test year 2006 is 8.65% as calculated on HELCO-1801.

Q. Why is 8.65% a fair return on rate base for test year 2006?

A. A rate of return on rate base of 8.65% for HELCO is fair because it satisfies the three requirements for fairness established by the Bluefield and Hope cases.

The requirements for "fairness," as set forth in Bluefield Water Works & Improvements Co. v. Public Service Commission of West Virginia (262 U.S. 679, 1923) and in Federal Power Commission v. Hope Natural Gas Company (320 U.S. 391, 1944), are that the return should:

1) Be commensurate with returns on investments in other enterprises having corresponding risks and uncertainties;
2) Provide a return sufficient to cover the capital costs of the business, including service on the debt and dividends on the stock; and
3) Provide a return sufficient to assure confidence in the financial integrity of the enterprise so as to maintain its credit and capital-attracting ability.

A return on rate base of 8.65% for HELCO for test year 2006 will satisfy these requirements for fairness.

Q. Are these criteria consistent with the criteria used by the Commission in prior rate cases?

A. Yes. These criteria were used by the Commission in numerous HELCO rate case decisions including Decision and Order ("D&O") No. 18365 (Docket No. 99-0207, HELCO 2000 Test Year), D&O No. 15480 (Docket No. 94-0140, HELCO 1996 Test Year), D&O No. 13762 (Docket No. 7764, HELCO 1994 Test Year), D&O No. 11893 (Docket No. 6999, HELCO 1992 Test Year) as well as numerous Hawaiian Electric Company, Inc. ("HECO") and Maui Electric Company, Limited ("MECO") rate case decisions.

Q. How should a fair return on rate base be developed in these proceedings?

A. A percentage return on rate base that is at least equal to the Company's composite cost of capital would be a fair rate of return in this docket.

Q. Why must a fair rate of return on rate base be at least equal to HELCO's composite cost of capital?

A. The composite cost of capital represents the carrying cost of the money received from investors to finance the rate base. In order to adequately compensate those who have invested in the Company, HELCO needs to be allowed a reasonable opportunity to earn at least its composite cost of capital.

Further, a rate of return on rate base at least equal to the Company's composite cost of capital would satisfy the three requirements of a fair return, provided that the Company is given a realistic opportunity to actually earn the return. A finding by the Commission of a return on rate base at least equal to the Company's composite cost of capital would allow the Company to cover the capital costs of the business; it would provide a return on investment commensurate with returns on other investments having corresponding risks; and it would provide assurances to the financial community of the Company's financial integrity (or financial strength).

COMPOSITE COST OF CAPITAL

Q. What is the composite cost of capital?

A. The composite cost of capital is the weighted average cost of short-term debt, long-term debt, hybrid securities, preferred stock, and common equity of the Company. It represents the carrying cost of the money received from investors to finance the rate base.

Q. How is the composite cost of capital calculated?

A. The composite cost of capital is calculated by summing the weighted effective costs of each element of the capital structure. The capital structure is made up of the short-term debt, long-term debt (revenue bonds and taxable debt), hybrid securities, preferred stock, and common equity of the Company. The overall cost of each of the elements is calculated taking into account such items as issuance costs to come up with an "effective" cost for each element. The "effective" cost of each element of the capital structure is "weighted" in proportion to its percentage in the capital structure to come up with a weighted effective cost.

Q. Has the same method been used by HELCO, HECO, and MECO in prior rate cases?

A. Yes. This method was used in Docket No. 99-0207 (HELCO 2000 Test Year), Docket No. 94-0140 (HELCO 1996 Test Year), Docket No. 7764 (HELCO 1994 Test Year), and Docket No. 6999 (HELCO 1992 Test Year) as well as numerous HECO and MECO rate cases.

Q. What is the Company's average estimated composite cost of capital for test year 2006?

A. The Company's estimated average composite cost of capital is 8.65% for test year

2006, as shown on HELCO-1801.

GOALS IN FINANCING

Q. What are the Company's overall goals in determining its financing?

A. In determining its financing, the Company strives to balance:

1) obtaining funds at the lowest reasonable cost, and

2) preserving the financial strength of the company.

Obtaining Funds at the Lowest Reasonable Cost

Q. How does the Company obtain funds at the lowest reasonable cost?

A. Low cost funds are obtained by: 1) issuing securities that are relatively low risk to investors and 2) minimizing the Company's business and financial risks, to the extent the Company can control those risks and it is appropriate to do so in the context of the Company's overall business plan.

Q. What securities do investors consider to be relatively low risk?

A. Investors consider debt issuances to be relatively low risk securities since there is assurance that the investor will be paid a stated rate at predetermined periods before other types of investors are able to get disbursements from the Company. Debt is usually the least costly source of funds for the Company.

Q. Why doesn't the Company obtain all its financing from debt?

A. Although debt is low risk to investors, it is relatively high risk to the Company. Higher proportions of debt would mean more fixed obligations and higher risk of default on debt covenants. This would increase the cost of the debt since lenders would need more compensation for taking more risk if there are more fixed obligations. Also, investors will not lend money to companies with no equity support. Some level of equity support is necessary in order to access the debt market. Therefore, the Company must balance the relatively lower cost debt with relatively higher cost equity in determining its capital structure.

Maintaining Financial Strength

Q. Why is it important for the Company to maintain its financial strength?

A. Investors are very sensitive to financial strength considerations when they decide where to invest their money. If HELCO's financial strength is not maintained, more risk adverse investors will invest their money elsewhere. This, in turn, will have negative implications for HELCO's customers because it will reduce the demand for the Company's securities and will increase its cost of capital. Further, under adverse market conditions, it may be difficult to attract capital. It is imperative from a customer standpoint, therefore, that HELCO at least maintain its current financial strength.

Q. How is financial strength measured?

A. One of the principal measures of a company's financial strength is its credit rating. Credit ratings are issued by independent rating agencies, such as Standard and Poor's ("S&P") or Moody's Investors Services ("Moody's"). A credit rating is an impartial opinion of the general creditworthiness of a company (issuer credit rating) or the creditworthiness of a company with respect to a particular security (issue-specific credit rating). Credit rating agencies evaluate the investment risk in commercial paper, secured and unsecured debt, hybrid securities, and preferred stock. The rating for each security reflects the investment risk in that security, given the rating agency's overall evaluation of the financial condition of the company and the particular characteristics of the individual security.

Q. Why is it important for the Company to maintain good credit ratings?

A. It is important to maintain good credit ratings for the following reasons:

1) Maintaining good credit ratings helps to minimize electric rates by lowering

the cost of capital to the Company. A credit rating is a measure of credit risk. All other things being equal, a company with less risk will have a lower cost of capital.

2) Maintaining good credit ratings gives the Company the ability to consistently attract new capital on reasonable terms, whatever the current state of the financial markets. The Company raises its capital in a competitive market. The supply and demand for investors' funds change as economic conditions change. Under ideal conditions, financing is available for most companies. Under adverse economic conditions, however, companies with weaker credit ratings may find it difficult, if not impossible, to raise new capital. A good credit rating assures investors that the company is financially sound, so that they will continue to have an interest in purchasing the company's securities. For example, many companies (including HELCO) restrict their investment portfolios to investments in companies that have ratings that are at least "investment grade."[3] Continuous access to capital markets is critical for a capital-intensive company such as HELCO that has an obligation to provide utility services.

Q. How do rating agencies determine credit ratings?

A. In order to determine a company's credit rating, the rating agencies evaluate a wide range of qualitative and quantitative factors that affect the company's credit quality. This assessment considers both the business risks and the financial risks of the company.

Q. How are HELCO's credit ratings measured?

[3] Standard & Poor's rating of BBB- or higher or Moody's rating of Baa3 or higher. See S&P "Rating Definitions" on HELCO-1809.

A. HELCO's credit ratings from S&P and Moody's are based on the collective financial strength of HECO, MECO, and HELCO:

Long-term debt (unsecured): Because HECO guarantees the payment of principal and interest on both MECO's and HELCO's unsecured long-term debt, the rating agencies evaluate the consolidated HECO to get a credit rating for all of the Companies' unsecured long-term debt.

Preferred Stock: HECO guarantees the obligations of MECO and HELCO, but only if HECO has already met its own preferred stock obligations. The rating agencies recognized this "junior position" of the subsidiary preferreds in each of their last sales (MECO's Series H and HELCO's Series G). Therefore, all subsidiary preferreds are treated as one notch lower in credit quality than HECO's preferred stock.

Hybrid Securities: Because HECO guarantees the obligations of MECO and HELCO, the rating agencies evaluate the consolidated HECO to get a credit rating for all of the Companies' hybrids.

Q. If, to some degree, HELCO trades on HECO's consolidated credit rating, why is it important for HELCO to also have a sound capital structure?

A. In order to minimize intercompany subsidization, to the extent it is practical, which would occur if the credit risks of the Companies were significantly different from each other, HELCO seeks to maintain its own financial strength, as an individual company, in accordance with the rating agency guidelines and HECO's credit ratings.

Business Risks

Q. What things do the rating agencies consider in assessing business risk?

A. Business risk considerations include industry characteristics, competitive position (e.g. efficiency, regulation, technology and marketing), and management.

Q. What business risks do the Company face?

A. The Company faces numerous business risks.[4] I will discuss several business risks here, although the Company faces many other business risks.

1) Capital Investments

The Company's level of estimated capital expenditures will be much higher relative to prior years as the Company invests in transmission additions and upgrades to improve reliability and to support growth. Construction of facilities may face challenges due to public sentiment, politics, and permitting requirements. The processes to get all the approvals needed to install these capital additions can take many years and therefore put investor funds at risk for extended periods.

Being an island environment, Hawaii has no inter-ties to other sources of electricity and must build its own resources to meet its needs. This increases the significance of making investment in capacity and reliability; and underscores the importance of maintaining access to capital markets to have the financial resources to make necessary capital investments. The Company must be able to construct the facilities and to finance them in order to continue to provide reliable electric service.

2) DSM programs

The Company recognizes the need for and benefit to Hawaii of reducing Hawaii's dependence on fuel oil and central station generation to meet the electricity needs of our customers.

[4] See "Forward-Looking Statements" from HEI and HECO Form 10-K for the year ended December 31, 2005 filed as Exhibit HELCO-1810.

Since 1996, we have implemented energy efficiency demand-side management ("DSM") programs, which have provided incentives to our customers to implement measures that reduce the use of electricity or use electricity more efficiently. Companies incur risks when they encourage customers to reduce the use of their product, but the Commission has recognized these risks by allowing for the timely recovery of program costs, lost margins and shareholder incentives. HELCO is assuming continued regulatory support for DSM program costs and some form of alternative DSM utility incentive mechanism, as the Commission addresses issues of whether DSM incentive mechanisms are appropriate to encourage the implementation of DSM programs, and the appropriate mechanism(s) for such DSM incentives, in the Energy Efficiency Docket.

3) Renewable Portfolio Standards

The Renewable Portfolio Standards law ("RPS"), as amended by the Legislature in 2004 and in 2006, subject to S.B. No. 3185, C.D. 1 becoming effective, requires HELCO (in aggregate with HECO and MECO) to obtain certain percentages of sales from renewable electrical energy resources("RE").[5] Renewable electrical energy resources include electrical energy generated using renewable energy sources, and electrical energy savings brought about by renewable displacement technologies (such as solar water heating) or energy efficiency measures. The law also requires that a study be performed to look at the utility's capability of achieving the

[5] Each electric utility company that sells electricity for consumption in the state shall establish a renewable portfolio standard of: 10% by end of 2010, 15% by end of 2015, and 20% by end of 2020. At least fifty percent of the RPS must be met by electrical energy generated using renewable energy sources such as wind or solar.

standards based on a number of factors including impact on customer rates, utility system reliability and stability, costs and availability of appropriate renewable energy resources and technologies, permitting approval, and impacts on the economy, culture, community, and environment. Further, the law directs the Commission to develop and implement, by December 31, 2007, a utility ratemaking structure to provide incentives that encourage utilities to use cost-effective renewable energy resources (while allowing for deviation if the standards cannot be met in a cost-effective manner, or due to events or circumstances beyond the utility's reasonable control), determine the extent that any proposed utility ratemaking structure would impact utility profit margins, and report findings to the Legislature.

4) Regulatory actions

The Company has numerous regulatory actions pending before the Commission that will impact the credit rating agency assessment of HELCO's regulatory risk. The Company must continue to obtain regulatory rulings that demonstrate regulatory support to at least maintain its current risk level. Regulatory decisions that suggest the utility will not have regulatory support increase the Company's risk profile, its cost of capital, and ultimately costs to ratepayers.

This rate case will be a significant indicator of the regulatory environment in which HELCO does business. Key considerations include: timely and adequate rate relief, adequate return on equity, recovery of fuel and purchased-power costs, and recovery of capital investments.

5) Fuel oil supply and importance of energy cost adjustment clause

Though the Company has undertaken many efforts to diversify its fuel sources, a major portion of the electricity is generated from oil-fired power plants. Substantial reliance on a single source of fuel makes the Company vulnerable to changes in supply and price of that resource.

The current energy cost adjustment clause ("ECAC") mechanism substantially reduces the Company's risk with regard to fuel oil prices. Changes to the ECAC could significantly impact the Company's ability to recover fuel oil costs and the purchase power energy costs incurred under long term power purchase agreements ("PPAs"), especially in a high fuel price environment. The ECAC allows the Company to mitigate the risk of sudden or frequent fuel cost changes. The ECAC also ensures that the utility's customers benefit from falling fuel oil and purchase power costs. Investors view the ECAC as a means to substantially reduce HELCO's risk of fuel oil and purchase power reliance. Continuation of the ECAC is vital to maintaining stable earnings potential and financial strength, and preserves, to the extent reasonably possible, the Company's financial integrity.

6) <u>Hawaii economy</u>

The Company's operating results are influenced by the volatility of the national and state economy and their impact on the economy of the island of Hawaii. Tourism, the largest component of Hawaii's economy, can fluctuate significantly as a result of terrorist acts across the globe, the geopolitical and war situation, and national and international economic conditions. A large portion of the Company's revenues comes from customers associated with the tourist industry. The impact of having such a large single customer sector is that it potentially creates volatility in the

Company's revenues.

7) Environmental laws and regulations

The electric industry faces stricter environmental laws and regulations which regulate the operation of existing facilities, the construction and operation of new facilities, and the proper cleanup and disposal of hazardous waste and toxic substances. The Company is at risk for the direct cost of compliance as well as the economic consequences of any impact on operations.

8) Purchased power

The Company expects to purchase over 56%[6] of its energy from independent power producers. PPAs have been entered into based on the Company's obligations under the Public Utility Regulatory Policies Act of 1978 ("PURPA"), state laws and rules encouraging the purchase of power from non-fossil fuel producers and qualifying facilities under PURPA, and only with the Commission's determination that costs paid under the contracts were reasonable and approval of the contracts. The contracts are obligations that must be paid before shareholders receive any compensation for their use of funds. HELCO investors receive no compensation for the PPAs, but have earnings potential at risk if power purchase costs are not fully recovered in rates (through base rates or the ECAC).

Although there have been no major changes to those contracts in recent years, there have been changes in generally accepted accounting principles that may impact the financial statement presentation of the contracts. There is uncertainty as to what impact the changes in accounting

[6] See HELCO-403.

treatment might have on the investment community's view of those contracts. S&P has increased its risk assessment of HELCO's firm capacity PPAs. I will further discuss these issues later in my testimony.

9) <u>Pension</u>

The Company faces risks with respect to the changes in value of pension assets, changes in assumptions used to calculate retirement benefits and changes in funding requirements. As Mr. Fujioka discusses in HELCO T-9, under SFAS 87[7], the accounting treatment of the pension changes when the Accumulated Benefit Obligation ("ABO") exceeds the fair value of the pension fund assets. If the ABO exceeds the fair value of the pension fund asset by as little as $1 at the measurement date (which is December 31st): (1) a liability, equal to the difference between the ABO and the fair value of the pension fund assets, is recognized, (2) the prepaid pension asset is eliminated, and (3) the liability which is recognized, along with the prepaid pension asset which is eliminated, net of taxes, is charged directly to a component of equity, called accumulated other comprehensive income ("AOCI"). Mr. Fujioka addresses steps taken by HELCO to mitigate this risk, including making voluntary contributions to the fund, and HELCO's pending application before the Commission.

In addition, we are aware that credit rating agencies evaluate risks associated with companies' pension plans and pension funding and may make specific financial ratio adjustments relating to pensions. To date, neither S&P nor Moody's have raised any specific concerns relating to

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[7] Financial Accounting Standards Board ("FASB") Statement of Financial Accounting Standards No. 87 ("SFAS 87"), "Employers' Accounting for Pension".

HELCO's pension fund, and I'm not aware of any specific adjustment made to HELCO's financial ratios by either S&P or Moody's relating to pension. I believe that the Company's contributions to the pension fund in the past three years have helped to reduce the potential for concerns that might have been raised by credit rating analysts and that the contributions generally have a positive impact on the Company's credit quality. Mr. Fujioka discusses the Company's funding of the pension fund in HELCO T-9.

Q. Have the Company's business risks changed since its last rate case?

A. Yes, since the Company's last rate case, the utility industry experienced restructuring, rating agencies increased their scrutiny of companies, accounting standards changed and the economy experienced volatility.

Utility Industry Restructuring

Q. How has the utility industry changed?

A. Deregulation of the electric utility business was implemented in a substantial number of states in the late 1990's. The impact of deregulation was very different in different states. Perhaps the most obvious failure was that of California with its energy shortfalls and the financial deterioration of its two largest electric utilities: the bankruptcy of Pacific Gas and Electric and near insolvency of Southern California Edison.

Based on S&P data shown below, beginning in 2000 and through 2003, the industry saw widespread financial deterioration and tightening of the capital markets. In 2004 and 2005, while more balanced than in previous years, there continued to be more downgrades than upgrades.

Standard & Poor's Rating Changes[8]

Year	Downgrade	Upgrade	Total	% Downgrade
2000	65	20	85	76
2001	81	29	110	74
2002	182	15	197	92
2003	139	8	147	95
2004	33	18	51	65
2005	46	36	82	56

Q. How has the change in the industry impacted HELCO?

A. Although HELCO does not face the "deregulated" environment that much of the mainland does, the fact that a utility declared bankruptcy changed investors' perception of risk for investor-owned electric utilities and caused much greater and closer scrutiny of utility regulatory environment. Changes in our regulatory environment, such as those inherent in the RPS law, the increased reliance on DSM (but with a re-assessment or even elimination of the risk protection and recognition associated with the existing lost margin and shareholder incentive recovery mechanisms), and consideration of a competitive bidding requirement for new generation, could significantly impact HELCO's financial performance.

Throughout the industry, there is increased awareness that historical regulatory stability does not assure current and future regulatory stability. Investors are increasingly sensitive to the risk of change in the way utilities are regulated. Investors want confidence that the regulators' decisions will be consistent and fair.

<u>Scrutiny of and by Credit Rating Agencies</u>

Q. How did the increased scrutiny of credit rating agencies impact HELCO?

A. Increased scrutiny of credit rating agencies prompted the credit rating agencies to

[8] S&P Article "U.S. Utility Downside Rating Actions Moderated Significantly in 2004" (HELCO-1811). S&P Article "Pace of U.S. Utility Rating Actions Picked Up in 2005; Downgrades Dominate" (HELCO-1812).

reassess how they determine credit ratings. Some examples of what HELCO saw as changes at the credit rating agencies included: additional assessments of financial arrangements, renewed focus on established criteria for qualitative and quantitative measures used to establish credit ratings, and more stringent adherence to the range of values used in quantified measures.

Q. What was involved in the assessment of financial arrangements?

A. Moody's asked the Company to provide a listing of any "rating triggers"[9] contained in any contract or arrangement and copies of HECO's line of credit agreements. S&P requested liquidity information and requested responses to another survey regarding rating triggers, which needs to be updated annually.

Q. What are some examples of renewed focus on established criteria?

A. In May 2003, S&P published an update of its methodology for evaluating PPAs. See S&P publication entitled "'Buy Versus Build': Debt Aspects of Purchased-Power Agreements" in HELCO-1813. In 2004, S&P published new guidelines for business risk assessments. See S&P publication entitled "New Business Profile Scores Assigned for U.S. Utility and Power Companies; Financial Guidelines Revised" in HELCO-1814.

Q. What are some examples of more stringent adherence to guidelines?

A. S&P required companies to maintain financial ratios within stated criteria. Furthermore, as I mentioned, S&P recently reassessed HELCO's PPAs and increased the risk factor that it applies to calculate the imputed debt related to the purchase power contracts. The risk factor was raised from 15% to 30%. This resulted in doubling the "imputed debt" for HELCO, which I discuss later.

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[9] A "rating trigger" is when a contract or arrangement includes a provision that is triggered by a certain type of credit rating change.

Changes in Accounting Treatment

Q. What changes in accounting treatment impact HELCO?

A. Included in the wave of new accounting guidance were two that may significantly impact HELCO which I will discuss in detail:

1) Emerging Issues Task Force Issue No. 01-8 "Determining Whether an Arrangement Contains a Lease" ("EITF 01-8")
2) Financial Accounting Standards Board Interpretation No. 46 (revised December 2003) "Consolidation of Variable Interest Entities" ("FIN 46R")

EITF 01-8

Q. What is EITF 01-8?

A. EITF 01-8 specifies criteria under which service contracts, such as PPAs, are determined to be lease arrangements and subject to the requirements of Statement of Accounting Standards No. 13 "Accounting for Leases". See KPMG publication entitled "Lease Arrangements Have Broadened" in HELCO-1815.

Q. How has EITF 01-8 impacted HELCO?

A. EITF 01-8 applies prospectively to arrangements agreed to, modified, or acquired after May 28, 2003[10]. Therefore, EITF 01-8 affects contemplated new arrangements and contemplated modifications to existing arrangements. HELCO will discuss the potential implications of EITF 01-8 in conjunction with negotiations for any new or modified PPA. The major threat to HELCO's capital structure is the possibility that a PPA will be deemed an "arrangement containing a lease" and that the lease may be deemed to be a capital lease. Capital leases are

[10] The consensus in this Issue should be applied to (a) arrangements agreed to or committed to, if earlier, after the beginning of an entity's next reporting period beginning after May 28, 2003, (b) arrangements modified after the beginning of an entity's next reporting period beginning after May 28, 2003, and (c) arrangements acquired in business combinations initiated after the beginning of an entity's next reporting period beginning after May 28, 2003. EITF 01-8 par. 16.

considered a form of debt which would result in additional leverage being included in HELCO's capital structure.

Of its existing PPAs, reassessments of the HEP and PGV contracts have not been triggered.[11] HRD's amended contract and Apollo's restated and amended contract are considered capital leases within the scope of EITF 01-8. However, because there are no minimum lease payments since the payments are contingent on the wind, the impact of the contracts on HELCO's capital structure are nil.

<u>FIN 46R</u>

Q. What is FIN 46R?

A. FIN 46R is an interpretation of Accounting Research Bulletin No. 51, "Consolidated Financial Statements". It changed the criteria used to determine whether and how certain relationships should be reported on consolidated financial statements. The primary objective of FIN 46R is to provide guidance on the identification of, and financial reporting for, entities over which control is achieved through means other than voting rights. Entities meeting certain specific criteria are deemed "variable interest entities" ("VIE"). If an entity is determined to be a VIE, HELCO must determine whether or not HELCO is the "primary beneficiary". "Primary beneficiary" is the enterprise that will absorb a majority of the entity's expected losses, if they occur, or receive a majority of the entity's expected residual returns, if they occur, or both. The primary beneficiary must consolidate the VIE. See summary section of FIN 46R in HELCO-1816.

Q. How has FIN 46R impacted HELCO?

[11] A reassessment of whether the arrangement contains a lease after the inception of the arrangement shall be made only if (a) there is a change in the contractual terms, (b) a renewal option is exercised or an extension is agreed to by the parties to the arrangement, (c) there is a change in the determination as to whether or not fulfillment is dependent on specified property, plant, or equipment, or (d) there is a substantial physical change to the specified property, plant, or equipment. EITF 01-8, par.13.

A. FIN 46R may change the accounting for certain PPAs. In addition, there may be other potential future transactions that are affected by FIN 46R.

Q. What is the impact of FIN 46R on PPAs?

A. Assessment of the potential impact of FIN 46R on HELCO's PPAs is ongoing. Throughout the electric industry, there have been numerous issues raised as to whether and/or how FIN 46R should be applied to PPAs. Although the power purchaser has no ownership interest in the power producer, certain interpretations of FIN 46R would result in the power purchaser consolidating the financial statements of the power producer.

The accounting profession recognizes that there is inconsistency in applying and problems in implementing FIN 46R. The electric industry is hopeful that additional guidance on FIN 46R will be forthcoming[12]; however, there is no assurance of further guidance.

HELCO has requested information from HEP, PGV, HRD, and Wailuku River Hydroelectric, and they have declined to provide information.[13] Due to the restated and amended PPA that HELCO has with Apollo, Apollo is required to provide information necessary to determine if HELCO must consolidate Apollo

[12] In June 2004, EITF released EITF 04-7, "Determining Whether an Interest Is a Variable Interest in a Variable Interest Entity." EITF 04-7 was in response to concerns by constituents that FIN 46R is unclear as to how a reporting enterprise should determine whether a contract absorbs variability of an entity's net assets exclusive of variable interests; that is, whether the contract should be considered a variable interest. Different approaches for making that determination have been developed and used, which has resulted in inconsistent identification of certain interests as variable interests. The issue was discussed at the June 30-July 1, 2004 EITF meeting and further discussion is expected at a future meeting. See HELCO-1817.

[13] FIN 46R specifies: "An enterprise with an interest in a variable interest entity or potential variable interest entity created before December 31, 2003, is not required to apply this Interpretation to that entity if the enterprise, after making an exhaustive effort is unable to obtain the information" necessary to (1) determine whether the entity is a variable interest entity, (2) determine whether the enterprise is the variable interest entity's primary beneficiary, or (3) perform the accounting required to consolidate the variable interest entity for which it is determined to be the primary beneficiary. "This inability to obtain the necessary information is expected to be infrequent, especially if the enterprise participated significantly in the design or redesign of the entity."

under FIN46R. HELCO is in the process of obtaining the information necessary to complete its determination of whether Apollo is a VIE and, if so, whether HELCO is the primary beneficiary.

Q. How is the PPA accounted for in this rate application?

A. Because HELCO is still in the process of obtaining the information necessary to complete its determination of whether Apollo is a variable interest entity and, if so, whether HELCO is the primary beneficiary, this rate application currently does not include any impacts of FIN46R.

<u>The Economy</u>

Q. How has the economy changed?

A. The terrorist attacks on America on September 11, 2001 and the subsequent war on terrorism and Iraq war, severely impacted the economy. While the economy has recently rebounded, HELCO did endure several years of slow economic growth, particularly in tourism, and increased cost of fuel.

Q. How has the economy impacted the industry?

A. The industry saw a decline in creditworthiness and increased competition for investor funds. The sluggish economy and the industry restructuring, which I discussed earlier, resulted in unprecedented number of credit downgrades beginning in 2000 through 2003. In more recent years, while more balanced than in previous years, there continued to be more downgrades than upgrades.

Q. How has the economy impacted HELCO?

A. The economy has impacted HELCO in several areas:

1) The recent economic situation reflected the potential volatility of the tourism market, and fuel oil prices, which emphasizes the vulnerability of operating in an island environment. As I discussed earlier, these are among

the major business risks faced by the Company.

2) The economic situation in the United States resulted in tightened capital markets which prompted the federal government to lower interest rates in recent years. Lower interest rates have allowed the Company to redeem or retire several issuances of higher cost obligations and issue lower cost securities. The results of the refinancings are reflected in HELCO's embedded long-term debt, hybrid securities and preferred stock. Ratepayers will pay less in interest and preferred dividends as a result of the interest rate environment that prevailed in recent years.

3) The threats of terror attacks have increased the need for physical security of our facilities and increased the cost of security and insurance.

Q. How do HELCO's business risks impact its capital structure?

A. Increased business risks have increased the pressure to reduce financial risk in order to maintain the Company's credit rating. Since HELCO cannot control much of the business risk it faces, HELCO must be resolute in controlling its financial risk. The primary means of reducing its financial risk is by increasing or, at minimum, maintaining the proportion of equity in its capital structure.

Financial Risk

Q. What do rating agencies consider in evaluating financial risk?

A. Financial risk considerations include financial characteristics, financial policy, profitability, capital structure, cash flow protection and financial flexibility.

Q. How do rating agencies measure financial risk?

A. To assess the financial risk of a company, the rating agencies examine a number of measures, including the following[14]:

1) Funds from operations/interest coverage – measure of ability to pay interest from operations.
2) Funds from operations/total debt – measure of ability to pay total debt from operations.
3) Total debt to total capital – measure of the financial leverage used by the company.

Q. What are HELCO's projected ratios for the test year?

A. HELCO's projected ratios are provided on HELCO-1818.

Q. What are the implications of the projected ratios?

A. A comparison of HELCO's projected ratios to the financial guidelines applicable to HELCO is shown on HELCO-1818. Based on a current business profile assignment of "5", without rate relief:

- the funds from operations/interest coverage ratio is indicative of a BBB rating (3.4 in BBB range of 2.8-3.8),
- the funds from operations/total debt ratio is indicative of a BB/BBB rating (15 in BB range of 10-15; BBB range of 15-22) and
- the total debt/total capital ratio is indicative of a BBB rating (53 in BBB range of 60-50).

With rate relief:

- the funds from operations/interest coverage ratio is indicative of a A/AA rating (4.5 in A range of 3.8-4.5; AA range of 4.5-5.5),
- the funds from operations/total debt ratio is indicative of an A rating (23 in A

[14] Standard & Poors "New Business Profile Scores Assigned for U.S. Utility and Power Companies; Financial Guidelines Revised" dated June 2, 2004 in HELCO-1814.

range of 22-30) and

- no change to the total debt/total capital ratio which is indicative of a BBB rating (53 in BBB range of 60-50).

Q. How does the Company's capital structure affect its financial risk?

A. Companies that have more debt (less equity) are deemed to have higher financial risk than companies that have less debt (more equity).

Q. What adjustments to debt amounts reported on the Company's financial statements do credit rating agencies make?

A. S&P has indicated that they make adjustments in two areas:

1) Imputed debt for PPAs

The credit rating agencies have determined that certain obligations of the Company that are not reported as liabilities on the Company's balance sheet should be reflected as debt in the ratios used to evaluate the Company's risk profile. In order to capture the risks associated with these obligations, the credit rating agencies calculate "imputed debt." In HELCO's case, the credit rating agencies impute debt for its firm capacity PPAs.

2) Equity credit for hybrid securities

Hybrid securities have certain features that are equity-like. In calculating ratios, S&P treats hybrids as debt, but gives some equity credit for the hybrids. The equity aspects of the hybrids decline over time.

Q. How does S&P calculate the imputed debt for the PPAs?

A. S&P takes the present value of the total fixed payments over the life of the contracts, using a 10% discount rate for the present value calculation. It then determines a risk factor to apply to the contract to reflect the riskiness to the utility based on the terms of the contract and assurances of cost recovery. S&P recently refined its approach to assigning risk factors. S&P increased the risk factor that it uses for HELCO's contracts from 15% to 30%, based on the existing contracts being in base rates and the ECAC.[15] The risk factor is applied to the present value of the fixed payments under the contract to calculate the imputed debt:

Risk Factor x Present Value of Fixed Contract Payments = Imputed Debt

Q. What is the impact of the imputed debt for the PPAs on HELCO's total debt to total capitalization ratio?

A. The imputed debt for HELCO's PPAs increases its December 31, 2005 total debt to total capitalization ratio from 48% to 53% as shown on HELCO-1818.

Q. Why is it important for the Company to establish and maintain a sound capital structure?

A. Whereas the Company has little control over many of the business risks it faces, the capital structure impact on financial risk is a risk that the Company can largely control.

Q. What are the Company's test year capital structure ratios?

A. The test year capital structure is comprised of 7.59% short-term debt, 37.44% long-term debt (which includes 30.96% revenue bonds and 6.48% taxable debt), 2.41% hybrid securities, 1.73% cumulative preferred stock, and 50.83% common equity. These capital structure ratios are appropriate to at least maintain HECO's existing credit ratings, of which HELCO's capital structure is a part. Through ongoing discussions and periodic meetings with the credit rating agencies, we are able to stay informed of investor perceptions of the Company. Feedback from the rating agencies is key in considering these ratios.

[15] S&P further indicated that cost recovery that is assured by legislation would warrant a 15% risk factor. Conversely, if cost recovery did not include energy price fluctuations recovered though ECAC, a risk factor of 50% would be appropriate.

Q. How do these ratios compare to what was allowed by the Commission in HELCO's last rate case [Docket No. 99-0207 (HELCO 2000 Test Year Rate Case)]?

A. In D&O 18365, Docket No. 99-0207, the Commission established rates based on a capital structure of: 5.78% short-term debt, 36.78% long-term debt, 7.75% hybrid securities, and 49.69% common equity. The proportion of common equity increased slightly since its last rate case in 2000 as HELCO's business risk has increased. In response to the increase in business risk, HELCO has found it necessary for the proportion of equity to increase. On several occasions over the past several years, we have received indications from the rating agencies that lower credit ratings were being considered unless HECO, of which HELCO is a part, was able to increase the equity in its capital structure.

Q. How will customers benefit from the increase in equity in HELCO's capital structure?

A. Maintaining credit quality will provide continued access to the capital markets to fund capital projects in order to fulfill our obligation to provide electric service. It provides continued assurance of reasonable financing rates, terms and conditions.

SOURCES OF INVESTOR FUNDS

Q. What are the Company's sources of capital funds?

A. The Company has the following sources of capital funds:

1) Short-Term Borrowings,
2) Long-Term Borrowings (revenue bonds and taxable debt),
3) Hybrid Securities,
4) Cumulative Preferred Stock, and
5) Common Stock.

Q. Please describe the Company's short-term borrowings.

A. HELCO borrows short-term from HECO, when HELCO has cash needs.

Q. Please describe the Company's long-term borrowings.

A. The Company's long-term borrowings consist of revenue bonds issued by the State of Hawaii and taxable debt. The proceeds of the revenue bond issuances are loaned to HELCO by the State. HELCO is obligated to repay the interest and principal of the bonds. Interest income to revenue bondholders is generally not taxable for Federal and State of Hawaii income tax purposes, therefore investors are willing to accept lower interest rates than taxable investments. Ratepayers benefit through the lower cost source of funds, as will be more fully described later in my testimony when I discuss the revenue bond savings calculations.

Q. Please describe the new taxable debt issuance that is reflected in the Company's long-term borrowings for the 2006 Test Year.

A. At the time the estimates were prepared, the Company assumed it would issue $50 million of taxable debt, at a 6% interest rate. Accelerated tax depreciation assumptions for the test year consistent with taxable debt financing are reflected in the exhibits and workpapers for witness T-13.

An application for the approval of the taxable debt financing was filed with the Commission on December 29, 2005, Docket No. 05-0330, and is pending approval. The long-term borrowings for 2006 may have to be updated later, depending on the outcome of the financing docket, with consistent revisions in depreciation assumptions, if any.

Q. Please describe the Company's hybrid securities.

A. Hybrid securities have some debt-like features and some equity-like features, hence the name "hybrid". HELCO's hybrid securities consist of junior subordinated deferrable interest debentures ("QUIDS"). The QUIDS are sold to trusts which exist for the purpose of issuing cumulative quarterly income preferred securities ("QUIPS"). The QUIPS have features similar to the QUIDS and are sold to third parties. An illustration of the transaction is shown on HELCO-1819. QUIDS have a lower after-tax cost than preferred stock because the periodic interest payments are deductible from taxable income, as are interest payments on traditional long-term debt. The equity-like features of the QUIDS are that they are deeply subordinated, have long maturity, and have a feature that permits the deferral of payments for a period of time.

Q. Please describe the Company's cumulative preferred stock.

A. Preferred stock issuances have stated dividend rates and may have sinking fund redemption provisions. Preferred dividends must be paid before dividends to the common shareholder can be paid.

Q. Please describe the Company's common equity.

A. As a wholly-owned subsidiary of HECO, the Company's common equity balance consists of the funds invested by its shareholder as well as income earned by the shareholder, but not distributed to it (retained earnings).

CAPITAL STRUCTURE

Q. How did you estimate the balances of each of the sources of investor funds?

A. We started with the recorded balances as of December 31, 2005, then we estimated changes in 2006.

Q. How were the changes estimated?

A. The estimate of changes was derived from the sources and uses of investor funds (e.g. earnings and capital expenditures) and redemptions or new issuances of external financing.

Q. How is HELCO's external financing plan determined?

A. The Company's external financing plan is structured to achieve the sound capital structure discussed earlier in my testimony.

Short-Term Borrowing Balance

Q. What is the average short-term borrowing balance for test year 2006?

A. The Company estimates average short-term borrowings of $29 million. The calculation of the average balance is shown on HELCO-1802.

Q. How was the average annual short-term debt amount for test year 2006 computed?

A. The average short-term debt amount was computed by averaging the recorded short-term debt balance at the end of 2005 and the estimated short-term debt balance at the end of 2006.

Q. How was the year-end 2006 short-term debt balance estimated?

A. We started with the recorded short-term debt balance as of December 31, 2005. The recorded year-end 2005 balance was then adjusted for estimated changes in 2006 to come to an estimated year-end 2006 balance.

Long-Term Borrowing Balance

Q. What is the average long-term borrowing balance for test year 2006?

A. The Company forecast average long-term borrowings consist of revenue bonds of $117 million and taxable debt of $25 million. The detailed list of revenue bond and taxable debt issuances, and other adjustments that constitute the average balance, are shown on HELCO-1803 and HELCO-1804.

Q. How was the average annual long-term debt amount for test year 2006 computed?

A. The average long-term debt amount was computed by averaging the net proceeds of the components of long-term debt (revenue bonds and taxable debt) at the end of 2005 and 2006.

Q. How was the year-end 2006 net proceeds of long-term debt balances estimated?

A. We began with the long term debt balance as of December 31, 2005. Based on the expected financing needs of the Company, the terms of the debt currently outstanding and the prevailing interest rates, we anticipate that HELCO would have one new taxable debt issuance in 2006.

We then calculated the net proceeds as of year-end 2006. The net proceeds are equal to the face amount, or par value, of the securities, less any unamortized balances of:

1) issuance costs,
2) issuance discounts,
3) revenue bond investment differentials, and
4) redemption costs.

Only "drawndown amounts" are included in the calculation of net proceeds.

Q. What are issuance costs?

A. Issuance costs are costs incurred as a result of selling securities. They include legal costs, insurance costs, printing costs, underwriters' fees, and other miscellaneous costs of issuing the securities.

Q. What are issuance discounts?

A. Issuing a security at a discount means that it was sold for less than its face value. At maturity, the full face value will be paid to the bondholder. This approach is attractive to certain buyers who are willing to take the security at a lower effective interest rate in order to get the capital appreciation from the discounted price to the par value at maturity.

Q. Why are bonds sometimes sold at a discount?

A. Selling at a discount can sometimes reduce the effective cost of the bonds, including the amortization of the issuance discount.

Q. What are revenue bond investment differentials?

A. The proceeds from revenue bond sales are put in a construction fund administered by a Trustee. "Drawdowns" from the fund are made for qualified projects. The undrawn proceeds left in the construction fund are invested and earn interest income until they are needed to fund projects. At the same time, interest payments must be made to the revenue bond holders for all of the revenue bonds, including those bonds that provided money still in the construction fund. The investment differential is effectively the difference between the earnings and the interest costs of the undrawn proceeds in the construction fund.

Q. What are the possible types of revenue bond investment differentials?

A. Revenue bond investment differentials can result in any of these situations:

1) "net expense", or negative investment differential -- interest income is less than the interest expense associated with the undrawn proceeds;
2) "net income", or positive investment differential -- interest income is more than the interest expense associated with the undrawn proceeds; or
3) No investment differential -- net expense equals net income

HELCO-WP-1803 p. 4 shows details of the revenue bond investment differentials.

Q. What are redemption costs?

A. Redemption costs are incurred as a result of redeeming securities early (before their maturity dates) in order to achieve cost savings by replacing existing securities with less expensive securities. When the Company redeems a security before its maturity date, it is usually required to pay to the holder of the security its par value plus an additional amount called a redemption premium.

Redemption costs include redemption premiums and other miscellaneous costs such as legal and trustee fees.

Q. What are "drawndown amounts"?

A. The proceeds from revenue bond sales are put in a construction fund administered by a Trustee. "Drawdowns" from the fund are made for qualified expenditures. "Drawndown amounts" refer to the disbursements from the fund to the Company.

Q. Why are some funds left undrawn?

A. Funds are left in the construction fund when there are no qualified expenditures to support the disbursement from the fund or it is not economic to support the disbursement from the fund with a specific project due to tax consequences.

Q. Why does HELCO sometimes sell bonds before it needs the money?

A. HELCO sometimes sells the bonds before it needs the money for several reasons:

1) to obtain as much low cost tax-exempt financing as it can before possible changes in legislation curtail the availability of this form of financing;
2) to secure an allocation of revenue bonds from the limited amount of revenue bond "cap" that the State of Hawaii Department of Budget and Finance receives each year; and
3) to save costs; it generally costs less to do less frequent, larger sales, instead of several smaller sales.

However, HELCO would sell bonds only if it is projecting an eventual need for the funds.

Q. Why are the net proceeds used to determine the average balance?

A. We use the net proceeds because the net amount is all the funds from those security sales that provide cash available to be invested in assets.

<u>Hybrid Securities Balance</u>

Q. What is the average hybrid security balance for test year 2006?

A. The Company estimates average hybrid securities of $9 million. The hybrid security issuance that constitutes the average balance is shown on HELCO-1805.

Q. How was the average annual hybrid security amount for test year 2006 computed?

A. The average hybrid security amount was computed by averaging the net proceeds of hybrid securities at the end of 2005 and 2006.

Q. How was the year-end 2006 net proceeds of hybrid security balances estimated?

A. We began with the balance as of December 31, 2005. HELCO does not anticipate any redemptions or new issuances to impact the hybrid securities balance in 2006. We then calculated the net proceeds as of year-end 2006. The net proceeds for hybrid securities are equal to the face amount of the QUIDS less any unamortized balances of issuance costs and redemption costs.

<u>Preferred Stock Balance</u>

Q. What is the average preferred stock balance for test year 2006?

A. The Company estimates average preferred stock of $7 million. The detailed list of preferred stock issuances and adjustments which constitute the average balance is shown on HELCO-1806.

Q. How was the average annual preferred stock amount for test year 2006 computed?

A. The average preferred stock amount was computed by averaging the net proceeds of preferred stock at the end of 2005 and 2006.

Q. How was the year-end 2006 net proceeds of preferred stock balances estimated?

A. We began with the December 31, 2005 balances. The Company does not anticipate any new issuances or redemptions of preferred stock between the recorded year-end 2005 through 2006. The net proceeds are equal to the face amount, or par value, of the preferred stock, less any unamortized balances of issuance costs. The only change to the balance during that period is the amortization of unamortized costs.

Common Equity Balance

Q. What is the average common equity balance for test year 2006?

A. The Company estimates average common equity of $193 million. The calculation of the average balance is shown on HELCO-1807.

Q. How was the average common equity amount for test year 2006 computed?

A. The average common equity amount was computed by averaging the net proceeds of common equity at the end of 2005 and 2006.

Q. How was the year-end 2006 net proceeds of common equity balance estimated?

A. We began with the recorded December 31, 2005 common equity balance. The unamortized issuance cost of hybrids and preferred stock was restored (added back) to the recorded common equity balance. The result is the common equity balance for ratemaking purposes as of December 31, 2005.

We then reflected the activity for 2006 for the estimated net changes in accumulated retained earnings. This calculation is shown in HELCO-1807.

Restoration of Unamortized Hybrid and Preferred Stock Issuance Costs

Q. Why is an amount of common equity equal to the unamortized hybrid and preferred stock issuance costs restored to the book common equity balance (included in "Restoration" on HELCO-1807)?

A. For financial statement purposes, the unamortized issuance costs of hybrids and preferred stock are shown as a reduction to common equity. For ratemaking purposes, however, they are shown as a deduction to hybrids and preferred stock rather than common equity since these costs relate to the hybrids or preferred stock.

Q. Has the Commission used this adjustment in the past in calculating the Company's common equity balance?

A. Yes. In all final Decision and Orders for the Companies' recent rate cases, the Commission used this adjustment to restore common equity.

Capital Structure Summary

Q. Ms. Sekimura, please summarize your testimony of capital structure.

A. A capital structure comprised of 7.59% short-term debt, 37.44% long-term debt (which includes 30.96% revenue bonds and 6.48% taxable debt), 2.41% hybrid securities, 1.73% cumulative preferred stock, and 50.83% common equity is appropriate.

CAPITAL COSTS

Short-Term Borrowings

Q. What is the estimated cost of short-term borrowings for the test year 2006?

A. The cost of short-term borrowings for the test year 2006 is estimated to be 5.0%.

Q. How was the cost of short-term borrowings determined?

A. We began with the most recent Blue Chip Financial Forecast[16] for federal funds which showed quarterly rates for 2006 of: 4.5%, 4.8%, 4.9%, and 4.9%. We calculated an average for 2006 of 4.78%. We increased this federal funds rate by 10 basis points to reflect the typical spread between federal funds rates and HECO's short-term borrowing rate. We noted that forecasts for 2006 have recently been trending upward; therefore we rounded our estimate to 5.0%.

Long-Term Borrowings

Q. What is the estimated effective cost of long-term borrowings for the test year 2006?

A. The estimated effective cost of long-term borrowings for the test year 2006 is

[16] Forecast dated March 1, 2006.

5.9% for revenue bonds and 6.2% for taxable debt.

Q. How was the effective cost of long-term borrowings determined?

A. The effective cost of long-term borrowings was calculated by dividing (a) the total annual requirement for interest and the amortization of unamortized items by (b) the net proceeds received from the sale of the securities. This calculation is shown on HELCO-1803 and HELCO-1804.

Q. What makes up the annual requirements?

A. The annual requirements consist of the annual interest expense plus the annual amortization of various costs of issuing and carrying the security. The average annual requirements for the test year are shown in column (E) of HELCO-1803 and HELCO-1804.

Q. What types of amortized costs are included in calculating the annual requirement?

A. Costs associated with financings that are incurred in only specific periods, but result in a benefit during the entire life of the security, are amortized. Amortized costs include:

1) issuance costs and issuance discounts,
2) revenue bond investment differentials, and
3) redemption costs, unamortized issuance costs for redeemed bonds, and unamortized investment income differential balances for redeemed bonds.

<u>Issuance Costs and Issuance Discounts</u>

Q. Why should ratepayers pay the costs of issuing bonds or issuing them at a discount?

A. It is appropriate for ratepayers to pay for the issuance costs and issuance discounts because the ratepayers get the benefits from these actions.

Revenue Bond Investment Differentials

Q. How is the revenue bond investment differential treated for ratemaking purposes?

A. The treatment of the revenue bond investment differential depends on whether there is net income or net expense.

Q. When there is net income in the revenue bond investment differential, how is it accounted for in the effective cost of long-term debt?

A. When there is net income, there are two possible situations:

1) When net income does not have to be rebated to the IRS, the positive investment differential is amortized, effectively reducing the annual requirements of the bonds.

2) When net income must be rebated to the IRS, the Company's net proceeds available for use would be increased by any net income until it is rebated to the IRS in five years.[17] This was done for the Series 1988 revenue bonds. Since increased net proceeds, for the same annual requirement, means a lower effective cost of the bonds, customers would receive the benefit for the five years that any net income is held by the Company.

Q. When there is net expense in the revenue bond investment differential, how does the revenue bond investment differential affect the annual requirements of the revenue bonds?

A. When there is net expense, investment differentials are generally amortized (in proportion to the drawn funds) over the life of the revenue bonds. This effectively increases the annual requirements of the bonds.

[17] Generally, for revenue bonds issued after 1986, the net income must be rebated to the IRS (with some exceptions), with the first rebate payment due five years after the issue.

Redemption Costs and Unamortized Costs for Redeemed Bonds

Q. Why should ratepayers pay the costs of redeeming bonds at a premium, unamortized issuance costs for redeemed bonds, and unamortized investment income differential balances for redeemed bonds?

A. It is appropriate for ratepayers to pay for redemption premiums, unamortized issuance costs for redeemed bonds, and unamortized investment income differential balances for redeemed bonds because ratepayers get the benefits from the bond redemption. When HELCO pays a premium to refund a high interest rate bond early, the customers benefit from the lower rates of the new issuance.

Q. Has the Commission included these types of costs in determining the effective costs of the Company's securities in prior rate cases?

A. Yes. In all final Decision and Orders for the Companies' recent rate cases, the Commission has included these types of costs in the effective cost calculation.

Hybrid Securities

Q. What is the estimated cost of hybrid securities for the test year 2006?

A. The estimated effective cost of hybrid securities for the test year 2006 is 7.50%.

Q. How was the cost of hybrid securities determined?

A. The effective cost of hybrid securities was calculated by dividing (a) the total annual requirement for interest and the amortization of unamortized items by (b) the net proceeds received from the sale of the securities. This calculation is shown on HELCO-1805.

Preferred Stock

Q. What is the estimated cost of preferred stock for the test year 2006?

A. The estimated effective cost of preferred stock for the test year 2006 is 8.37%.

Q. How was the cost of preferred stock determined?

A. The effective cost of preferred stock was calculated by dividing (a) the total annual requirement for interest and the amortization of unamortized items by (b) the net proceeds received from the sale of the securities. This calculation is shown on HELCO-1806.

Common Equity

Q. What would be a fair and reasonable rate of return on common stock equity to be used by the Commission in determining the revenue requirements in this docket?

A. In HELCO T-17, Dr. Roger Morin, a Professor of Finance and an expert in this area, has determined that in his opinion a fair and reasonable return on common equity for HELCO for test year 2006 would be 11.25%. Dr. Morin did a comprehensive analysis before arriving at his judgment on a fair and reasonable return on common equity for HELCO.

Q. Do you accept Dr. Morin's conclusion that a fair return on common equity for HELCO in this docket is 11.25%?

A. Yes. An allowed rate of return on equity of 11.25% should give the Company an opportunity to earn a fair and reasonable rate of return in the test year, assuming that the Company obtains adequate rate relief by the beginning of the test year.

Q. When was Dr. Morin's appraisal of the fair return on equity ("ROE") for HELCO conducted?

A. It was completed in April 2006.

Capital Costs Summary

Q. Ms. Sekimura, please summarize your testimony on costs of capital.

A. The test year estimates of capital costs for the test year of: short-term debt 5.00%, long-term debt which includes revenue bonds 5.90% and taxable debt 6.20%, hybrid securities 7.50%, cumulative preferred stock 8.37%, and common equity

11.25% are appropriate.

DETAILED ANALYSIS OF HEI IMPACT NOT NEEDED

Q. Has a comprehensive analysis of HEI's impact on the Companies' cost of capital been done before?

A. Yes. Dennis Thomas and Associates, an independent consultant, was hired to assist the Public Utilities Commission in its investigation of the effects of the relationship between HEI and HECO on the operations of HECO and its electric subsidiaries, HELCO and MECO, and their respective ratepayers. In January 1995, Dennis Thomas and Associates issued a report titled, "Review of the Relationship between Hawaiian Electric Industries and Hawaiian Electric Company" (the "Thomas Report").

Q. What did the Thomas Report conclude regarding the impact of HEI on the Companies' cost of capital?

A. The Thomas Report concluded the following:

1) "Any impacts of diversification on the yield of HECO's debt obligations have likely been transitory and small. Hence, there is no reason to believe that the debt costs reflected in HECO's rates have been changed as a result of HEI's past diversification activities." (Thomas Report, page 132)

2) "Cost of equity witnesses in HECO rate cases have consistently based their estimates on HECO's financial parameters and estimates for the cost of equity to comparable electric utilities . . . the policy of looking directly at HECO and comparable electric utilities, rather than HEI's cost of equity, has served to insulate HECO's ratepayers from any impact due to changes in HEI's cost of equity." (Thomas report, page 131)

3) ". . . diversification has not permanently raised or lowered the cost of

capital incorporated into the rates that the utility's customers pay." (Thomas Report, page 121)

Q. Did the Commission adopt the Thomas Report?

A. Yes. The Commission adopted the Thomas Report in D&O No. 15225. In its D&O, the Commission also adopted the Department of Defense's recommendation that in rate proceedings the Companies "... present comprehensive analysis of the impact that the holding company structure and investments in non-utility subsidiaries have on its cost of capital to the utility." However, the Commission stated that it "... will apply the recommendation on a case-by-case basis in the Utilities' respective rate cases." (emphasis added) As a result, it is our understanding that the Commission will determine whether a "comprehensive analysis of the impact that the holding company structure and investments in non-utility subsidiaries have" on the cost of capital of HELCO should be done in this case.

Q. In previous rate cases, what have the Companies done to address the issue as to whether such a comprehensive analysis should be done?

A. HECO, MECO and HELCO retained Mr. William E. Avera to address the issue in each of their latest test year rate cases [Docket No. 04-0113 (HECO 2005 Test Year), Docket No. 97-0346 (MECO 1999 Test Year), Docket No. 97-0420 (HELCO 1999 Test Year), and Docket No. 99-0207 (HELCO 2000 Test Year)]. Mr. Avera was the Team Leader for Dennis Thomas and Associates with respect to those sections of the Thomas Report addressing cost of capital issues (including financial integrity and credit ratings). Mr. Avera's team assembled the material for Chapter 6 – Availability and Cost of Capital to HECO.

Q. What was Mr. Avera's conclusion?

A. Mr. Avera's conclusion is stated in each of his affidavits dated December 28, 1997 (see MECO-1610 in Docket No. 97-0346), March 1, 1998 (see HELCO-1610 in Docket No. 97-0420), October 7, 1999 (see HELCO-1710 in Docket No. 99-0207), and November 8, 2004 (see HECO-2118 in Docket No. 04-0113. In summary, through evaluations that focused primarily on events since the Thomas report was issued in January 1995, Mr. Avera arrived at the following conclusion:

> "In conclusion, my review revealed no evidence that would alter the conclusions reached in the Thomas Report or indicate a fundamental change in investors' perceptions of the relationship between HEI and HECO. The comprehensive analyses conducted in preparing the Thomas Report required almost an entire year to complete and involved an exhaustive review of documents and extensive interviews with members of the investment community in Hawaii, on Wall Street, and in other financial centers. Given that the findings of such a comprehensive review with respect to the availability and cost of capital to HEI and its utility subsidiaries would not be expected to be materially different from those adopted by the PUC in December 1996, it is my opinion that the significant expenditure of time and money involved in conducting such a comprehensive review is not presently warranted."

Q. Did HECO, MECO and HELCO agree with Mr. Avera's conclusions?

A. Yes. A "comprehensive" analysis, such as that done as part of the Thomas Report, was not conducted in connection with the HECO, MECO and HELCO rate cases.

Q. Did the Commission require that a comprehensive analysis be conducted in any of those cases?

A. None was required in the HECO 2005 test year rate case, MECO 1999 test year case, or the HELCO 2000 test year case. The HELCO test year 1999 rate case was withdrawn in 1999.

Q. What has HELCO done to address the issue as to whether such a comprehensive analysis should be done in this case?

A. HELCO has again retained Mr. Avera.

Q. What is Mr. Avera's current conclusion?

A. Mr. Avera's conclusion is stated in his affidavit, a copy of which is attached as HELCO-1820. After conducting an evaluation that focused primarily on events since his last review in 1999, Mr. Avera concluded the same as in his past three affidavits – in part, "my review revealed no evidence that would alter the conclusions reached in the Thomas Report," and "a comprehensive review is not presently warranted."

Q. Does HELCO agree with Mr. Avera's current conclusion?

A. Yes. A "comprehensive" analysis, such as that done as part of the Thomas Report, is not warranted in this case.

SAVINGS FROM REVENUE BONDS

Q. H.R.S. Section 39A-208(b) requires that the Commission, in every rate case, make estimates of the savings to HELCO's customers resulting from the use of special purpose revenue bonds. Have you prepared such an estimate for the Commission?

A. Yes. The savings estimate, along with an explanation of the savings calculation, is shown in HELCO-1821.

CONCLUSION

Q. What is your conclusion regarding the fair rate of return on rate base for test year 2006?

A. The Company believes that the rate of return on rate base found fair and reasonable by the Commission should not be less than its composite cost of capital, and that the Company's composite cost of capital in test year 2006 is expected to be 8.65%. The 8.65% composite cost of capital includes a rate of return on common equity of 11.25%, which is important to the maintenance of the

Company's credit quality.

Q. Does this conclude your testimony?

A. Yes, it does.

HELCO RT-18
DOCKET NO. 05-0315

REBUTTAL TESTIMONY OF
TAYNE S. Y. SEKIMURA

FINANCIAL VICE PRESIDENT

HAWAII ELECTRIC LIGHT COMPANY, INC.

Subject: Rate of Return on Rate Base

INTRODUCTION

Q. Please state your name and business address.

A. My name is Tayne S. Y. Sekimura and I am the Financial Vice President of Hawaii Electric Light Company, Inc. ("HELCO" or the "Company"). My business address is 900 Richards Street, Honolulu, Hawaii, 96813.

Q. Have you previously testified in this proceeding on the return on rate base?

A. Yes, I have presented direct testimony as HELCO T-18 and supplemental testimony as HELCO ST-18 and supporting exhibits and workpapers.

Q. What is the purpose of your rebuttal testimony?

A. The purpose of this testimony is to address the following:

1. Present the Company's updated composite cost of capital which includes:
   a. The average 2006 test year based on 2006 recorded balances;
   b. Explanation of the ratemaking treatment of the December 31, 2006 accumulated other comprehensive income ("AOCI") charges to equity for the defined-benefit pension and postretirement benefits other than pensions ("OPEB") plans; and
   c. Updated financial ratio calculations.
2. Address the settlement agreement with the Consumer Advocate and the Consumer Advocate's testimony regarding:
   a. The Company's Energy Cost Adjustment Clause ("ECAC");
   b. Cost of capital and financial ratios based on the terms of the settlement agreement with the Consumer Advocate;
   c. Keahole writedown;
   d. The Consumer Advocate's proposed pension tracking mechanism;
   e. HELCO's proposal for an OPEB tracking mechanism which is patterned

after the Consumer Advocate's proposed pension tracking mechanism;

f. Business risks and the related impact on return on equity;

g. Adjustment to cost of common equity for HELCO's higher risks;

h. Risk of rate base disallowances of construction costs; and

i. The Consumer Advocate's financial ratio calculations.

UPDATED COMPOSITE COST OF CAPITAL

Q. What is HELCO's updated composite cost of capital for test year 2006?

A. HELCO's updated composite cost of capital is 8.61% as shown in HELCO-R-1801.

Q. What updates have you made to the cost of capital calculation?

A. The cost of capital filed in direct testimony was revised to reflect the following changes:

1. Updated the capitalization balances to reflect December 31, 2006 recorded. This changed the short-term borrowing, long-term borrowing, taxable debt, and common equity amounts. Since these amounts changed, the proportions of all components of cost of capital changed.
2. Updated the long-term debt earnings requirement based on 2006 recorded.
3. For ratemaking purposes, restored common equity for the AOCI charges related to pension and OPEB plans as of December 31, 2006.

These changes are shown in HELCO-R-1801, HELCO-R-1802, HELCO-R-1803, HELCO-R-1804 and the related workpapers.

Short-Term Borrowing

Q. What is the revised average short-term borrowing balance for test year 2006?

A. The average short-term borrowing balance of $50 million, which is higher than the $29 million presented in direct testimony, is shown on HELCO-R-1802.

Q. Why did the short-term borrowing balance change?

A. The average short-term borrowing balance increased because the 2006 year end recorded short-term borrowing balance is higher than the 2006 year end forecast presented in direct testimony. This was primarily due to the level of capital expenditures which the Company had anticipated funding with a taxable debt issuance. Because the taxable debt was not issued in 2006, cash needs were instead financed with short-term borrowings.

Q. What is the revised estimated cost of short-term borrowings for test year 2006?

A. The 5% estimated cost of short-term borrowings presented in direct testimony is still reasonable in light of the 5.18%[1] experienced in 2006. Therefore, no revisions were made to the estimated cost of short-term borrowings for the test year 2006.

Long-Term Borrowing

Q. What is the revised average long-term borrowing balance for test year 2006?

A. The average long-term borrowing balance, shown on HELCO-R-1803, is $117 million, which is slightly lower than the estimate presented in direct testimony.

Q. What adjustments contributed to the change in the long-term borrowing balance?

A. Changes to the long-term borrowing balance are attributable to the 2006 recorded unamortized cost related to the Syndicated Credit Facility ("SCF") and unamortized issuance cost related to the revenue bond issuance that the Company is anticipating in 2007. HELCO's proposal to recover the unamortized SCF cost through the cost of capital calculation for ratemaking was discussed in HELCO's response to CA-IR-448. The unamortized balances and calculations are shown on

[1] 5.18% is the 2006 average monthly rate on HELCO's short-term borrowings. The monthly rates on HELCO's short-term borrowings are derived from HECO's weighted average commercial paper borrowing rate for that corresponding month.

HELCO-R-1803 and HELCO-RWP-1803.

Q. What is the revised estimated effective cost of long-term borrowings for test year 2006?

A. The Company has revised the estimated effective cost of long-term borrowings for the test year 2006 to 5.92% from the 5.90% presented in direct testimony.

Q. Why did the effective cost of long-term borrowings increase?

A. The increase in the effective cost of long-term borrowings is due to an increase in the annual requirement resulting from the annual amortization of the SCF cost and a decrease in the average long-term debt balance as a result of the 2006 recorded unamortized issuance costs. The calculation of the effective rate is shown on HELCO-R-1803.

Taxable Debt

Q. Why was the taxable debt eliminated from the cost of capital calculation?

A. HELCO did not issue the taxable debt it had planned to issue in 2006. Therefore, the taxable debt was eliminated from the cost of capital calculation.

Common Equity and Restoration of AOCI Charges

Q. What is the revised average common equity balance for test year 2006?

A. The calculation of the average common equity balance of $192 million, which is slightly lower than the estimate presented in direct testimony, is shown on HELCO-R-1804.

Q. Why did the average common equity balance change?

A. The change in the common equity balance is due to the 2006 recorded change in retained earnings.

Q. What are the AOCI charges reflected in HELCO-R-1804?

A. Generally accepted accounting standards prescribe that certain situations result in charges to common equity, net of taxes, which are not reflected on the Company's income statement. These charges are made to an equity account entitled "accumulated other comprehensive income." In 2006, the Financial Accounting Standards Board issued Statement of Financial Accounting Standards No. 158, "Employers' Accounting for Defined Benefit Pension and Other Postretirement Plans an amendment of FASB Statements No. 87, 88, 106, and 132(R)" ("SFAS 158"). As discussed by Mr. Fujioka in HELCO RT-9, SFAS 158 changed the criteria which trigger AOCI charges for defined-benefit pension and OPEB plans.

Q. Has the Company incurred any AOCI charges to equity?

A. Yes. For financial statement reporting purposes, the Company incurred AOCI charges related to pension and OPEB plans as of December 31, 2006.

Q. How does the Company propose to treat the AOCI charges for ratemaking purposes?

A. For ratemaking purposes, the Company has restored common equity for the AOCI charges, as shown on HELCO-R-1804. As discussed by Mr. Fujioka in HELCO RT-9, the AOCI charges are included (net of the pension and OPEB liabilities) in rate base.

Q. Why is it proper to restore common equity for the AOCI charges for ratemaking purposes?

A. Shareholders have invested funds that exclude the deduction from (or addition to) equity for financial statement purposes for AOCI and should be allowed a return on invested funds. Therefore, the ratemaking cost of capital should be based on the equity balance excluding the deduction (or addition) for AOCI. If the AOCI adjustment is included in ratemaking equity, the equity ratemaking balance will fluctuate (higher or lower) depending primarily on the market value of the pension and OPEB funds. On Exhibit HELCO-R-1805, I provide an illustration of what the pension portion of the AOCI charge or credit to equity would have been in the period 1995 to 2006 if SFAS 158 had been in effect. As you can see, AOCI would have increased equity in 1996 through 2001. In some of those years, the increase would have been significant.

Q. Does the Commission's ruling in Docket No. 05-0310 impact the ratemaking treatment of the AOCI charge?

A. No. In Docket No. 05-0310, the Commission ruled that the Company could not record a regulatory asset for the amounts which would otherwise be charged to AOCI. The Commission did not address the ratemaking treatment of the AOCI charge.

Q. Do the pension and OPEB tracking mechanisms discussed later in your testimony impact the ratemaking treatment of the AOCI charges?

A. Yes. The pension and OPEB tracking mechanisms that are discussed later in my testimony would eliminate the AOCI charges for both book and ratemaking purposes.

<u>Revised Capital Structure</u>

Q. What is the revised capital structure?

A. As a result of the changes just described, a test year capital structure consisting of 13.24% short-tem debt, 31.37% long-term debt, 2.45% hybrid securities, 1.75% cumulative preferred stock, and 51.19% common equity is appropriate.

<u>Updated Financial Ratios</u>

Q. Have you updated the projected financial ratios for the test year as presented in your direct testimony?

A. Yes. We have updated the financial ratio calculations in HELCO-R-1806. There are two sets of ratios. One set is based on HELCO receiving rate relief and earning an 11.25% return on common equity. The other set is based on no rate relief.

Q. What are the implications of the updated ratios?

A. A comparison of HELCO's projected ratios to the financial guidelines applicable to HELCO is shown on HELCO-R-1806 (pages 3 and 4). Based on a current S&P business profile of "5", without rate relief:

- the funds from operations/interest coverage ratio is indicative of a BBB rating (3.5 in BBB range of 2.8-3.8),
- the funds from operations/total debt ratio is indicative of a BBB rating (16 in BBB range of 15-22), and
- the total debt/total capital ratio is indicative of a BBB rating (55 in BBB range of 60-50).

With rate relief:

- the funds from operations/interest coverage ratio is indicative of an AA rating (4.6 in AA range of 4.5-5.5),
- the funds from operations/total debt ratio is indicative of an A rating (23 in A range of 22-30), and
- no change to the total debt/total capital ratio, which is indicative of a BBB rating (55 in BBB range of 60-50).

SETTLEMENT AGREEMENT AND CONSUMER ADVOCATE POSITIONS

Energy Cost Adjustment Clause ("ECAC")

Q. Does the Consumer Advocate support the continuation of the existing ECAC?

A. Yes. The Consumer Advocate acknowledges the benefits to ratepayers of the existing ECAC and supports its continuation. See testimonies of Mr. Brosch in

CA-T-1, pages 22-23, and Mr. Herz in CA-T-2, page 64.

Cost of Capital and Financial Ratios Based on the Settlement Agreement

Q. Are the parties in agreement on the capital structure for ratemaking purposes?

A. Yes. As a result of settlement discussions, the Consumer Advocate and the Company agree to use a capital structure of 13.24% short-term debt, 31.37% long-term debt, 2.45% hybrid securities, 1.75% preferred stock and 51.19% common equity.

The Consumer Advocate's capital structure in its direct testimony mirrored the Company's direct testimony capital structure which was developed prior to the Company knowing that AOCI charges would apply as of December 31, 2006. Thus, it was not clear whether the Consumer Advocate's direct testimony capital structure considered HELCO's actual AOCI charges as of December 31, 2006 or the restoration to equity for the actual AOCI charges. In settlement discussions, the Company provided the Consumer Advocate with an explanation of the AOCI restoration. In calculating the average common equity balance for the 2006 test year, the Consumer Advocate has agreed to use the December 31, 2006 balance with the AOCI charges restored for ratemaking purposes.

Q. Are the parties in agreement on the cost of the various components of the capital structure other than the cost of common equity?

A. The parties agreed on the cost of short-term debt of 5.00%, cost of hybrid securities of 7.50% and cost of preferred stock of 8.37%. As indicated earlier in my testimony, the long-term debt rate was revised from the 5.90% presented in direct testimony to 5.92%. HELCO's proposal to recover the unamortized SCF cost through the cost of capital calculation for ratemaking was discussed in HELCO's response to CA-IR-448. However, the Consumer Advocate's testimony was based on the Company's direct testimony and did not reflect this update. In settlement discussions, the Consumer Advocate indicated that this change in long-term debt rate is acceptable if the increase was attributable to actual transaction costs incurred. The increase in the effective cost of long-term borrowings is due to an increase in the annual requirement resulting from the annual amortization of HELCO's share of the SCF cost and a decrease in the average long-term debt balance as a result of the 2006 recorded unamortized issuance costs. The calculation of the effective rate is shown on HELCO-R-1803. Therefore, the long-term debt rate is agreed upon at 5.92%.

Q. Have the parties reached agreement regarding the cost of common equity?

A. Yes. In the settlement agreement, the parties agreed to a cost of common equity of 10.7% as presented on HELCO-R-1801. In direct testimony, the Company requested a cost of common equity of 11.25% as presented by Dr. Morin in HELCO T-17. Dr. Morin maintains his cost of equity in his rebuttal testimony in HELCO RT-17 at 11.25%. The Consumer Advocate's witness, Mr. Parcell, recommends a cost of equity rate of 9.5% to 10.25%.

Q. Why did the Company agree to settle the cost of common equity at 10.7% when it maintains that a return on common equity of 11.25% is necessary?

A. The agreement to settle the cost of common equity at 10.7% must be viewed in the context of the settlement agreement in total. As Mr. Lee explains in HELCO RT-1, the settlement agreement balances the interests of all parties, including ratepayers and investors. The cost of common equity of 10.7% included in the settlement agreement was necessary to reach settlement of all issues.

Q. Have you calculated the projected financial ratios for the test year based on the terms of the settlement?

A. Yes. The financial ratio calculations based on the settlement terms appear on HELCO-R-1806, pages 1 and 2. There are two sets of ratios. One set is based on HELCO receiving rate relief and earning a 10.7% return on common equity. The other set is based on no rate relief.

Q. What are the implications of the ratios based on the settlement agreement?

A. Based on a current S&P business profile of "5", with rate relief based on the terms of the settlement (See HELCO-R-1806, pages 1 and 2), the resulting ratios (compared to the ratios based on HELCO's updated cost of capital calculated prior to the settlement and shown in HELCO-R-1806, pages 3 and 4) indicate the following:

- the funds from operations/interest coverage ratio is slightly lower and is indicative of a AA/A rating (4.45 in AA range of 4.5-5.5; A range of 3.8-4.5),
- the funds from operations/total debt ratio is slightly lower and is indicative of an A/BBB rating (22 in A range of 22-30; BBB range of 15-22), and
- there is no change to the total debt/total capital ratio, which is indicative of a BBB rating (55 in BBB range of 60-50).

Keahole CT-4 and CT-5 Writedown

Q. What have the Parties agreed to with respect to Keahole CT-4 and CT-5?

A. The settlement reflects a write down of $12,898,000 of gross plant in service (or $12,000,000 net of accumulated depreciation) and $898,000 of accumulated depreciation associated with the CT-4 and CT-5 units at the Keahole generating station, with associated reductions in depreciation expense, accumulated deferred income taxes, unamortized state investment tax credit ("ITC") and amortization of state ITC.

Q. What was the Consumer Advocate's position with respect to Keahole CT-4 and

CT-5?

A. As explained by Mr. Fujioka in HELCO RT-9, the Consumer Advocate recommended that only $7.3 million of allowance for funds used during construction ("AFUDC") be recovered which compares to the $21.7 million that HELCO accrued. Stated another way, the Consumer Advocate proposed a disallowance of $14.4 million ($21.7 million minus $7.3 million) of AFUDC, before taking into account the offset for accumulated depreciation. As explained by Mr. Fujioka in HELCO RT-9, approximately $1.5 million of the $14.4 million was previously approved by the Commission to be included in rate base when the Commission included Pre-PSD facilities in rate base in HELCO's 2000 test year rate case (Decision and Order No. 18365 dated February 8, 2001 in Docket No. 99-0207). The Consumer Advocate also proposed that certain costs for land use permitting and related litigation, noise abatement measures, landscaping, and land rezoning totaling approximately $9.6 million be disallowed (before accumulated depreciation offset). See Exhibit CA-101 Schedule B-8.

Q. What is the Company's overall position with respect to the above Consumer Advocate proposals?

A. As covered by other Company witnesses, the costs included represent costs associated with facilities that are used or useful and/or expenses that were prudently incurred by the Company to provide electric service. Therefore, the Commission should include such costs in its determination of revenue requirements for the 2006 test year. Costs that are prudently incurred by HELCO to provide electric service should be recovered from ratepayers.

The rate base calculation used in Hawaii results in a net rate base which approximately equals the amount of money committed by investors to plant in service. Rate base exclusions produce a net rate base which is less than the amount of investors' funds committed to plant in service. If the investment is not in the rate base or in construction work in progress (where the investors are compensated through AFUDC), there is currently no mechanism to earn a return on that investment. The inability to earn a return on part of the money invested would make it impossible (without offsetting circumstances of some sort) for the investors to earn the overall rate of return determined fair and reasonable by the Commission. This will ultimately lead to investors requiring higher returns as a result of the risk of earning lower returns due to disallowances.

Q. Why did the Parties agree to settle this issue?

A. Mr. Lee addresses this from HELCO's perspective in HELCO RT-1. Both parties recognized that hearings on the issue of the Keahole CT-4 and CT-5 would be long, arduous, and drain resources that they could otherwise put to more productive use. Many of the disputed items result from the specific situation and circumstances surrounding CT-4 and CT-5 rather than from broader policy issues for which hearings might be more appropriate or necessary. HELCO decided that all things considered, it would be best to accept the settlement, bring closure to the Keahole matter and allow HELCO to focus its attention on meeting the challenges of the future and providing efficient, reliable service to its customers.

Q. How will the settlement impact HELCO investors?

A. As a result of the settlement agreement, full recovery of Keahole CT-4 and CT-5 will no longer be deemed probable and the Company's net investment in Keahole CT-4 and CT-5 will be written down by approximately $12 million. HELCO's parent company, HECO, will issue a disclosure of the settlement in accordance with the requirements of the Securities and Exchange Commission. This writedown will result in an after-tax charge to net income in the first quarter of 2007 of approximately $7 million.

Investors in an electric utility, such as HELCO, need to have a realistic chance to earn the return determined fair and reasonable on their total investment in HELCO's electric utility business. Investors expect the Company to be able to recover prudently incurred costs from its customers. Exclusion of such costs from revenue requirements reduce income and diminish the ability of investors to earn the fair rate of return on equity.

However, acceptance of the settlement agreement by the Commission will eliminate the ongoing uncertainty of the ratemaking treatment of the Company's investment in Keahole CT-4 and CT-5. Further, timely rate relief will allow the Company the opportunity to improve earnings going forward. First quarter 2007 HECO consolidated earnings will be severely impacted. However, because this action is a one-time event relating to the unique situation at Keahole, the writedown relating to CT-4 and CT-5 may not significantly adversely impact investors' long-term perceptions of HELCO and its utility affiliates.

If, however, investors perceive the writedown as part of an overall reduction in regulatory support for prudent utility investments, the Company's business risk profile will increase. If investors perceive higher risks associated with making utility investments, this will increase the Company's cost of capital over the long term.

Consumer Advocate's Alternative Proposal – Pension Tracking Mechanism

Q. Does the Consumer Advocate accept the Company's pension cost estimate, pension asset in rate base, and restoration of equity for pension amount which was charged to AOCI?

A. The Consumer Advocate accepts the Company's pension cost estimate. See Ms. Price's testimony in HELCO RT-10. The Consumer Advocate also accepts the pension asset in rate base. As discussed by Mr. Fujioka in HELCO RT-9, the Company does not agree with the Consumer Advocate's method to determine when it was appropriate to include the pension asset in rate base. The Company has supported inclusion of the pension asset in rate base in Mr. Fujioka's direct and rebuttal testimonies (HELCO T-9 and HELCO RT-9) as well as in my rebuttal testimony in Hawaiian Electric Company, Inc. ("HECO")'s 2005 test year rate case (Docket No. 04-0113, HECO RT-16), Ms. Nanbu's direct testimony in HECO's 2007 test year rate case (Docket No. 2006-0386, HECO T-10) and Mr. Matsunaga's testimony in Maui Electric Company, Ltd. ("MECO")'s 2007 test year rate case (Docket No. 2006-0387, MECO T-9). As I mentioned earlier in my testimony, the Consumer Advocate accepts the restoration of equity for the pension and OPEB AOCI charges. The Parties agreed to the pension expense, pension asset in rate base, and AOCI restoration to calculate revenue requirements in this rate case; in addition, however, the Consumer Advocate proposed an alternative pension tracking mechanism.

Q. Please briefly describe the Consumer Advocate's pension tracking mechanism.

A. In CA-T-3, Mr. Carver presents the Consumer Advocate's alternative pension tracking mechanism. Under the alternative tracking mechanism, an amount is identified in each rate case as pension costs in rates. Once new rates are effective, and until rates are changed in a subsequent rate case, the amount of pension cost in rates is separately tracked. The mechanism requires that the Company make fund contributions at the actuarially calculated net periodic pension cost ("NPPC") as determined under generally accepted accounting principles subject to certain exceptions.[2] (Currently SFAS No. 87, "Employers' Accounting for Pensions", is the accounting guidance that addresses the calculation of NPPC.) At each rate case, the cumulative amount of pension cost in rates since the last rate change is compared to the cumulative amount of contributions to the pension fund. This net amount is an addition (if the cumulative fund contributions exceed the cumulative amount in rates) or deduction (if the cumulative amount in rates exceeds the cumulative fund contributions) in the calculation of rate base. The test year ending pension balance in rate base is then amortized over five years beginning when new rates are effective. The pension tracking mechanism would also allow the Company to reverse the pension AOCI charge to equity and create a regulatory asset for financial statement purposes.

Q. How would the pension cost in rates be determined?

A. The pension cost in rates would be the test year NPPC plus or minus the amortization of the ending pension amount in rate base. If cumulative contributions have exceeded the cumulative pension amount in rates (an addition to rate base), the amortization would be an addition to NPPC (i.e., future rates will be relatively higher). If cumulative pension amount in rates have exceeded cumulative contributions (a deduction in rate base), the amortization would be a deduction from NPPC (i.e., future rates will be relatively lower).

Q. Does the Company accept the Consumer Advocate's alternative pension tracking mechanism?

A. Yes, the Company and the Consumer Advocate have reached agreement on the pension tracking mechanism proposed by the Consumer Advocate. The Company

[2] The pension funding is further restricted to the ERISA minimum and tax deductible maximum. When NPPC is negative, there is no funding requirement.

proposed certain modifications to the tracking mechanism proposed by the Consumer Advocate to allow the Company greater flexibility for funding more than NPPC for certain specified reasons. In addition, the Company proposed language to clarify how the tracking mechanism will be implemented. Exhibits HELCO-R-1808 and HELCO-R-1809 reflect CA-304 and CA-305, respectively, modified for changes which have been agreed to by the Company and the Consumer Advocate.

Q. Do the revenue requirements filed in this rebuttal testimony, the settlement agreement, and the Statement of Probable Entitlement assume that the pension tracking mechanism is adopted?

A. Yes. The revenue requirements filed in this rebuttal testimony, the settlement agreement, and the Statement of Probable Entitlement all reflect adoption of the pension tracking mechanism. The revenue requirements include $2,554,000, which is the amortization of the ending pension asset balance (ending pension asset of $12,771,000 divided by 5), in addition to the test year NPPC of $2,744,000. These amounts are reflected in the testimonies of Mr. Fujioka in HELCO RT-9 and Ms. Price in HELCO RT-10. In addition, however, an alternative revenue requirement calculation without the pension tracking mechanism being adopted in the interim decision and order, and therefore without the pension asset amortization, is filed with the Statement of Probable Entitlement.

Q. How does the adoption of the pension tracking mechanism impact prior pension cost recovery?

A. The pension tracking mechanism does not apply retroactively and does not impact prior pension costs. The pension tracking mechanism applies prospectively from the date that the Commission issues an order which: (1) approves the adoption of the pension tracking mechanism and (2) establishes new rates that explicitly incorporate the provisions of the mechanism in the new rates. Until the pension tracking mechanism is adopted, ratemaking treatment of pension is based on the past practices of this Commission which treat pension expense in generally the same manner as other expenses which do not have special ratemaking treatment. In contrast, for example, fuel, Integrated Resource Planning, and Demand Side Management expenses have special ratemaking treatment based on specific Commission orders. HECO's consistent ratemaking treatment of pension costs in the past and the prohibition against retroactive ratemaking to pension were discussed in HECO's 2005 test year rate case (Docket No.04-0113) Opening Brief dated December 2, 2005 (pages 106 to 110) and Reply Brief of HECO dated December 19, 2005 (pages 5 to 6 and 14 to 16). Pension costs will not have special ratemaking treatment until the pension tracking mechanism is adopted by the Commission.

Q. When would the pension tracking mechanism be implemented?

A. The pension tracking mechanism would be effective on the date which the Commission issues an order which: (1) approves the adoption of the pension tracking mechanism and (2) establishes new rates that explicitly incorporate the provisions of the mechanism in the new rates. If the Commission's interim rate order in this docket includes: (1) approval to adopt the pension tracking mechanism and (2) interim rates that explicitly incorporate the test year NPPC of $2,744,000 and amortization of the pension asset of $2,554,000 (as described in the testimony of Ms. Price in HELCO RT-10 and Mr. Fujioka in HELCO RT-9), the pension tracking mechanism would be adopted as of the date of the interim rate order.

HELCO's Proposal for a Postretirement Benefits Other Than Pensions ("OPEB") Tracking Mechanism

Q. Please describe HELCO's proposal for an OPEB tracking mechanism.

A. HELCO has proposed a tracking mechanism for OPEB, which mirrors the pension tracking mechanism proposed by the Consumer Advocate. The proposed OPEB tracking mechanism, which incorporates revisions suggested by the Consumer Advocate, and comments further explaining the mechanism are provided on Exhibits HELCO-R-1810 and HELCO-R-1811.

Q. Does the Consumer Advocate accept the OPEB tracking mechanism?

A. Yes.

Q. How would implementation of the OPEB tracking mechanism impact revenue requirements in this case?

A. The adoption of the OPEB tracking mechanism would not impact revenue requirements in this docket. However, the OPEB tracking mechanism specifies ratemaking treatment which allows financial statement treatment of benefit costs to be smoothed based on the amount of net periodic benefit costs ("NPBC") established in this rate case and addresses potential situations in the future where contributions to OPEB trusts are not equal to the NPBC recognized. Adoption of the OPEB tracking mechanism would also allow the Company to reverse the OPEB AOCI charge to equity and create a regulatory asset for financial statement purposes.

Q. When would the OPEB tracking mechanism be implemented?

A. The OPEB tracking mechanism would be effective on the date which the Commission issues an order which approves its adoption. If the Commission's interim rate order in this docket includes: (1) approval to adopt the OPEB tracking mechanism and (2) interim rates that explicitly incorporate the test year OPEB costs of $1,530,400[3] (see testimony of Ms. Price in HELCO RT-10), the OPEB tracking mechanism would be adopted as of the date of the interim rate order.

Adjustment to Cost of Common Equity for HELCO's Higher Risks

Q. Do you have any comments on Mr. Parcell's statement on pages 60 through 62 of CA-T-4 that current circumstances do not warrant the upward adjustment of 35 basis points to HELCO's rate of return on equity, as proposed by Dr. Morin in HELCO T-17?

A. Yes, I do. Although HELCO and the Consumer Advocate have settled on a rate of return on common equity for this rate case, it is necessary for the Company to express its position on this issue in response to Mr. Parcell's arguments to the contrary. Mr. Parcell argues that HELCO's request for a 35 basis point adjustment above the cost of equity for comparison utilities should be denied in this proceeding. However, the market-derived cost of common equity for a group of proxy companies cannot simply be applied to HELCO without further analysis. A comparison must be made of the relative investment risk of HELCO versus that of the proxy companies selected by the experts. When the relative risk comparison is made, it is clear that HELCO has greater investment risk than that of the proxy group of comparable companies. As a result, the cost of common equity for HELCO is greater than the market-derived cost of common equity for such proxy companies.

[3] NPBC of $1,369,800 minus executive life portion of $103,300 plus FAS 106 regulatory asset amortization of $263,900

As Mr. Parcell notes, the Commission in prior Decisions and Orders[3] has recognized that HELCO has greater risks than both the Consumer Advocate's and HELCO's groups of comparable companies. Taking various risk factors into consideration, the Commission determined that an adjustment was necessary to allow for HELCO's greater risks as compared to the comparable companies. In Decision and Order No. 18365 (dated February 8, 2001) in Docket No. 99-0207, HELCO's 2000 test year rate case, the Commission stated:

> "HELCO urges us to consider adjustments to account for its greater risk, relative to the comparable companies. We agree that a risk adjustment is appropriate. HELCO's risk is inherent in its smaller size and is demonstrated by its higher operating ratio, lower quality of earnings, and weak level of internally generated funds for construction. In addition, its substantial purchase power obligations and bond ratings are matters which concern us.
>
> We find unpersuasive the Consumer Advocate's assertions that we need not make any risk adjustments. HELCO is financially weaker and subsequently riskier than all of the proxy groups. Therefore, it is appropriate to make an adjustment for HELCO's risk. Ultimately, both HELCO and its customers benefit when HELCO has sufficient financial integrity to attract capital. Accordingly, we believe that an upward adjustment of 50 basis points is warranted. By this adjustment, the rate of return on common equity rises to 11.5 per cent.
>
> We believe that this rate is supportive of HELCO's financial integrity and will enable HELCO to continue to attract capital."

Mr. Parcell starts his discussion of the reasons for his belief that the upward adjustment is no longer necessary, with a review of the Commission's adjustments. He notes on page 61 of his testimony that, "the impetus for the adjustments occurred during the 1993-1994 time period, as reflected in Commission orders in 1994-1995", during which time HECO, MECO and HELCO were experiencing downgrades of their securities. He also notes that

[3] See Decision and Order No. 18365 in Docket No. 99-0207, Decision and Order No. 15480 in Docket No. 94-0140 and Decision and Order No. 13762 in Docket No. 7764.

during that time period, the Commission's final rate case decisions were awarded at a slower pace. However, he made the same contention in HELCO's 2000 test year rate case (CA-T-13 at 60.), and the Commission explicitly found that an upward adjustment of 50 basis points was warranted, as quoted above.

Mr. Parcell then states that HELCO's financial status has improved and that the Commission's response time for rate cases has improved and that the Hawaii Commission is one of a few commissions to have an "above average" rating by Value Line. He further notes that HELCO's own perceptions of its relative risks have reflected a decline as the request of 35 basis points upward adjustment is lower than any previous Commission award. While we acknowledge that the Commission has been supportive, particularly by granting interim rate relief orders which reduce the negative financial impact of regulatory lag, Mr. Parcell's claim that HELCO's financial status has improved is unfounded. As shown on Exhibit HELCO-R-1807, HELCO's rate of return on rate base and rate of return on equity have steadily declined since 2002.

Many of the factors that adversely impact HELCO's business risk have been recognized by the Commission in prior rate case decisions and continue to apply in this case. They include: (1) HELCO's service territory is geographically isolated; (2) HELCO lacks interties, which precludes the Company from having other utility systems provide reliable backup generation sources; (3) there is a scarcity of generation sites in HELCO's service territory, (4) HELCO purchases a substantial percentage of its power through firm capacity contracts, which impacts HELCO's financial condition; (5) HELCO's service territory is significantly dependent upon tourism; (6) HELCO is significantly dependent on oil for electric generation; and (7) HELCO is a very small company.

Q. Please summarize the Company's position on whether a risk adjustment applies to HELCO.

A. The overall risks for HELCO are greater than for the comparable companies, and therefore an adjustment to the rate of return on common equity is still appropriate. HELCO needs the continuing support of the Commission to help it maintain its credit and to adequately compensate common stock investors – i.e., support demonstrated by the Commission's recognition of HELCO's greater business risks, as evidenced by the Commission's upward adjustment in what it determines to be a fair and reasonable rate of return on common equity for HELCO. Loss of this support would be detrimental in the rating agencies' assessments of the Company's business risks.

The Commission's responsive decisions for HELCO, including the upward adjustment made to the rate of return on common equity, have been important factors in helping HELCO maintain its financial integrity. The timing and adequacy of rate relief (including timely and adequate interim rate relief) affect the business risks of HELCO and are matters of concern to the rating agencies and investors.

Q. Is HELCO suggesting that there should be an adjustment to the 10.7% rate of return on common equity accepted in the settlement agreement?

A. No. HELCO supports the 10.7% rate of return on common equity as part of the global settlement of issues impacting revenue requirements. My testimony is intended to address Mr. Parcell's pre-settlement direct testimony, and not the settlement.

<u>Regulatory Process—Risk of Rate Base Disallowances of Construction Costs</u>

Q. On page 21 of Mr. Parcell's testimony, as part of his discussion regarding the regulatory climate in Hawaii, Mr. Parcell asserts that the regulatory process in Hawaii serves to minimize the risk of rate base disallowances. Mr. Parcell claims that the Commission's procedures which provide opportunities to review and approve expenditures for major construction projects prior to their appearance in a rate case proceeding results in significantly reducing the likelihood of rate base disapproval. He claims this reduces the Company's business risks. Do you have any comments on this?

A. Yes. It is the case that the Commission's prior review of construction projects helps to reduce the Company's business risk. The Commission has permitted the Company's capital expenditures to be included in rate base and has refrained from disallowing items because of changed circumstances. This is helpful in reducing regulatory risk, but does not eliminate it completely. There have been cases where the Companies have had to make substantial commitments of funds prior to Commission approval under paragraph 2.3(g)(2) of General Order No. 7 in order to maintain the schedule for a project essential to reliable service. The ability to move forward on these projects is essential to maintain the Company's obligation to serve, since the Company is not interconnected with other utilities and cannot import power as other utilities can. The writedown related to Keahole CT-4 and CT-5 eliminates the risk mitigation that Mr. Parcell suggests exists and has been factored into his return on equity calculations.

<u>Consumer Advocate's Financial Ratio Calculations</u>

Q. Do you have any comments on CA-414 which Mr. Parcell refers to in his contention that a 9.88% return on common equity (the midpoint of his 9.5% to 10.25% range) will provide sufficient earnings for HELCO to maintain its financial integrity?

A. Yes. On page 48 of his testimony, Mr. Parcell indicates his belief that his cost of capital recommendation provides the Company with a sufficient level of earnings to maintain its financial integrity. Mr. Parcell refers to his pre-tax interest coverage calculation (see CA-414) and indicates that the mid-point of his recommended range produces a coverage level (which he calculates at 3.38 times) which is within the benchmark range for a BBB rated utility (2.4-3.5 times). He also indicates that his calculation of the debt ratio is within the benchmark for an A rated utility (42-50%).

Assuming a 9.88% return on common equity (as noted in CA-414), the Company calculates a pre-tax interest coverage of 3.15 times, vs. the 3.38 times reflected in CA-414, which is within the benchmark range for a BBB rating (2.4-3.5 times). However, the Company does not agree with Mr. Parcell when he states that "the debt ratio (which reflects the capital structure as proposed by the Company) is within that benchmark for an A rated utility." Based on the percentages presented by Mr. Parcell in CA-414, the Company's total debt to total capital ratio is 52.6%, which indicates a BBB rating (53% in BBB range of 60-50%). As noted earlier in testimony under the Updated Financial Ratios section, the Company projects the total debt to total capital ratio for the test year to be indicative of a BBB rating (55% in BBB range of 60-50%).

CONCLUSION

Q. What is your conclusion as to the appropriate rate of return on rate base to use in calculating revenue requirements in this docket?

A. The rate of return on its full rate base should not be less than the Company's composite cost of capital. The settlement agreement, if accepted in total and if used as the basis for an interim rate increase, will provide timely rate relief to the

Company, and should help HELCO to better achieve and maintain financial integrity. The settlement agreement includes a composite cost of capital of 8.33% (Exhibit HELCO-R-1801 page 1), including a rate of return on common equity of 10.7%.

Q. Does this conclude your rebuttal testimony?

A. Yes, it does.

DOD-IR-75

Sekimura Direct, HECO-1906.

What return on equity was assumed for 2006 and 2007 in order to produce retained earnings estimates of $27.998 Mill. And $25.465 Mill, respectively? Please provide supporting analysis.

HECO Response:

A return on equity of 11.25% was assumed for 2006 and 2007, which is the same return on common equity presented in Direct testimony.

DOD-IR-76

Sekimura Direct, HECO-1913.

a) Please provide the spreadsheets used to calculate the financial ratios shown. Please provide those electronic documents with cells unlocked, formulas and all source data available.

b) Please show in detail how the 57% total debt/total capital ratio was calculated.

c) In HECO-1914, S&P reports the adjusted debt/capital ratio for HEI to be 56.7%. Please explain why HEI's consolidated debt/capital ratio of 56.7% is consistent with the 57% shown for HECO only on HECO-1913.

d) What is S&P's most current estimate of HEI's adjusted debt-to-capital ratio? Please provide supporting documentation from S&P.

HECO Response:

a. Please refer to HECO-WP-1913, pages 1 to 14. The electronic version of this worksheet was provided to the DOD on May 17, 2007.

b. Please see the schedule on page 2.

c. We are unable to locate the reference to that adjusted debt/capital ratio for HEI of 56.7%. In HECO-1914, page 3 and Table 2 on page 5, S&P reports the adjusted total debt-to-capital ratio for HEI to be 56% and 56.4%, respectively. It appears to be a coincidence that HEI's consolidated adjusted total debt-to-capital ratio of 56% is close to HECO's adjusted total debt-to-capital ratio of 57% as shown on HECO-1913.

d. S&P's most current estimate of HEI's adjusted debt-to-capital ratio is 61%. See S&P's report dated May 23, 2007 for HECO provided in HECO's response to DOD-11, page 3.

($ in thousands)

HECO	2005	2005 Ratio
Short-term Debt	91,715	6%
Hybrids	30,000	2%
IPP Debt Equivalent	302,161	19%
Lease Debt Equivalent	18,676	1%
Long-term Debt	451,132	29%
Total Debt	893,684	**57%**
Preferred Stock	22,293	1%
Common Stock Equity	655,544	42%
Total Capitalization	1,571,521	100%

DOD-IR-77

Referring to the Embedded Cost of Service Study in HECO-WP-2001, pages 1 through 161, please provide an electronic copy in Microsoft® Excel format, with all formulas intact, including all cost of service studies and all functionalization, classification, allocation and unitization at present rates, proposed rates and at equal rates of return.

HECO Response:

The Embedded Cost of Service Study in HECO-WP-2001 was previously provided electronically in this case. However, the Company is providing the electronic files as requested. Please refer to the accompanying electronic files in Excel format: "DOD-IR-77 HECO-WP-2001_Page 1.xls" and "DOD-IR-77 HECO-WP-2001_all other.xls".

DOD-IR-78

Referring to HECO-WP-2001, page 83 of 161, please provide workpapers showing the calculation of the Average Excess Demand (D1) allocation factor.

HECO Response:

The calculation of the Average Excess Demand (D1) allocation factor can be found in the workpaper for the Embedded Cost of Service Study provided in HECO's response to DOD-IR-77 on the tab "Page 3".

DOD-IR-79

Within the P-DP customer group in the cost of service study, please provide the number of customers, non-coincident customer demand and kilowatthours (or an estimate of each) associated with customers who receive service at the primary voltage level, but from the low side of a HECO-owned single customer substation that is fed from the HECO transmission system. Also provide the revenues under present rates and under proposed rates associated with such customers.

HECO Response:

Within the P-DP customer group in the cost of service study, there are 18 customers who receive service at the primary voltage level, but from the low side of a HECO-owned single customer substation that is fed from the HECO transmission system. The billing kW for these customers for the test year is 1,698,642.9 kW. The energy consumption for these customers for the test year is 698,251,200 kWh.

Revenues under present rates are $110,889,868 based on the June 2007 Update ECAF of 7.331 ¢/kWh. Revenues under current effective rates are $115,447,877. Current effective rates include an Interim Rate Increase of 7.04% as approved in Docket No. 04-0113, Interim Decision and Order No. 22050; and an estimated Interim Surcharge of 0.0694 ¢/kWh effective May 1, 2007, as approved in Docket No. 04-0113, Order No. 23377. Revenues at proposed rates are $123,618,193. Proposed rates include a billing credit of $1.75 per kWb for Customers directly served from a Distribution substation.

DOD-IR-80

Referring to the Estimate of Test Year Revenues in HECO-WP-2016, please provide an electronic copy in Microsoft® Excel format, with all formulas intact.

<u>HECO Response:</u>

The estimate of test year revenues by rate schedule in HECO-WP-2016 was previously provided electronically in this case. However, the Company is providing the electronic files as requested. Please refer to the accompanying electronic files in Excel format: "HECO-WP-2016_RateF.xls," "HECO-WP-2016_RateG.xls," "HECO-WP-2016_RateH.xls," "HECO-WP-2016_RateJ.xls," "HECO-WP-2016_RatePP.xls," "HECO-WP-2016_RatePS.xls," "HECO-WP-2016_RatePT.xls," and "HECO-WP-2016_RateR.xls,"

DOD-IR-81

Referring to HECO T-1, page 10, please provide a copy of the Adequacy of Supply report filed on March 6, 2006. Also, please provide all subsequent reports.

HECO Response:

See Attachments 1 and 2 for the Adequacy of Supply ("AOS") reports filed with the Commission on March 6, 2006, and on February 27, 2007, respectively. Attachments 1 and 2 are voluminous and available for inspection at HECO's Regulatory Affairs Division office, Suite 1301, Central Pacific Plaza, 220 South King Street, Honolulu, Hawaii. Please contact Dean Matsuura at 543-4622 to make arrangements to inspect the requested information. Electronic versions of the requested information are being provided on a compact disc.

DOD-IR-81
DOCKET NO. 2006-0386
ATTACHMENTS 1-2

Attachments 1 and 2 are voluminous and available for inspection at HECO's Regulatory Affairs Division office, Suite 1301, Central Pacific Plaza, 220 South King Street, Honolulu, Hawaii. Please contact Dean Matsuura at 543-4622 to make arrangements to inspect the requested information. Electronic versions of the requested information are being provided on a compact disc.

DOD-IR-82

Please provide all regular monthly and all other filings with the Commission, by month, for the period January 2004 through the most recent filing for the Energy Cost Adjustment.

HECO Response:

Attachments 1 to 4, which consist of HECO's monthly Energy Cost Adjustment filings from January 2004 to June 2007, are voluminous and available for inspection at HECO's Regulatory Affairs Division office, Suite 1301, Central Pacific Plaza, 220 South King Street, Honolulu, Hawaii. Please contact Dean Matsuura at 543-4622 to make arrangements to inspect the requested information. Electronic versions of the requested information are being provided on a compact disc.

DOD-IR-82
DOCKET NO. 2006-0386
ATTACHMENTS 1 - 4

Attachments 1 to 4 are voluminous and available for inspection at HECO's Regulatory Affairs Division office, Suite 1301, Central Pacific Plaza, 220 South King Street, Honolulu, Hawaii. Please contact Dean Matsuura at 543-4622 to make arrangements to inspect the requested information. Electronic versions of the requested information are being provided on a compact disc.

DOD-IR-83

Referring to the Energy Cost Adjustment Clause, as proposed, please provide the supporting detail for the proposed new base costs for fuel and purchased power, including the cost of each individual source in each category, the percentage weighting of each source in each category, and the workpapers showing quantities, cost per unit prices, and the weighted average values.

HECO Response:

Refer to HECO-931 to HECO-938 and HECO-WP-934 to HECO-WP-936 for Energy Cost Adjustment Clause exhibits and supporting workpapers.

DOD-IR-84

Please provide a copy of the NERA Report referenced at page 65 of HECO T-9.

<u>HECO Response:</u>

The requested report is provided on pages 2 to 38.

Hawaiian Electric Company, Inc. • PO Box 2750 • Honolulu, HI 9684

William A. Bonnet
Vice President
Government & Community Affairs

December 29, 2006

2006 DEC 29 P 2:58

PUBLIC UTILITIES COMMISSION

FILED

The Honorable Chairman and Members of the
Hawaii Public Utilities Commission
465 South King Street, First Floor
Kekuanaoa Building
Honolulu, Hawaii 96813

Dear Commissioners:

Subject: Docket No. 2006-0386 - HECO 2007 Test Year Rate Case
<u>Act 162 Consultant Report</u>

Enclosed for filing are the original and eight copies of the <u>Report on Power Cost Adjustments and Hedging Fuel Risks</u> prepared by NERA Economic Consulting.

Sincerely,

William A. Bonnet

cc: Division of Consumer Advocacy

December 29, 2006

Report on Power Cost Adjustments and Hedging Fuel Risks

Hawaiian Electric Company, Inc.

NERA
Economic Consulting

MMC Marsh & McLennan Companies

Table of Contents

List of Figures

List of Tables

I. INTRODUCTION

NERA Economic Consulting ("NERA") was retained by Hawaiian Electric Company, Inc. and its affiliates, Hawaii Electric Light Company ("HELCO") and Maui Electric Company ("MECO") (collectively, "HECO" or "the Utilities"), to evaluate whether its fuel adjustment clause ("FAC") – the Energy Cost Adjustment Clause ("ECAC") as it currently exists – is in compliance with Act 162, which was signed into law in June 2006.[1] In addition, HECO sought NERA's assistance with respect to fuel price hedging and other approaches to stabilizing end-user electricity rates to present to the Hawaii Public Utilities Commission ("HPUC" or "the Commission"). This report presents a summation of NERA's findings on these matters.

FAC mechanisms (and other similar cost adjustment and tracking mechanisms) give utilities a reasonable opportunity to recover their legitimate costs of procuring electricity on behalf of customers. By providing timely cost recovery for power costs, the amount of time between rate cases can increase. The breadth of adjustment clauses is not limited to fuel and purchased power expenses. Rather, the ECAC or a similar adjustment mechanism can be implemented efficiently for recovery of other costs that meet the three classic reasons for an automatic rate adjustment, which include:

1. The cost of the purchased resource is outside the control of the utility that purchases it.
2. The item accounts for a significant or large component of the utility's total operating costs.
3. Costs related to the resource are volatile and unpredictable.

Adjustment and cost tracking mechanisms may also be implemented to allow for the parallel treatment of similar costs categories. For example, demand-side management ("DSM") costs provide a substitute for pursuing supply-side resources. If supply-side resources are recovered under a FAC, DSM costs could be treated symmetrically, which would put supply- and demand-side energy costs on an equal footing.

The ECAC that HECO and its affiliates currently have in place is comparable to the FACs that are used by other traditionally regulated jurisdictions in the United States. Nearly all traditionally regulated and most restructured states in the US have some similar mechanism for power cost recovery. Like the ECAC, most (approximately 22) of the 30 restructured states with fuel clauses have some form of "true-up" mechanism to reconcile actual and forecasted costs. Also, thirteen of those states have rate adjustments on a quarterly or more frequent basis.

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[1] A Bill for an Act Relating to Energy, S.B. No. 3185, S.D. 2, H.D. 2, C.D. 1, Act No. 162 signed into law by the Governor of Hawaii on June 2, 2006 (hereinafter, "Act 162" or "the Act") amended Section 269-16 of the Hawaii Revised Statutes to include a subsection (g) that specifies requirements for the design of "any automatic fuel rate adjustment clause," of which the ECAC is one.

Both fuel costs and purchased energy costs are recovered through the ECAC. A weighted average of the various fuel and purchased energy costs is computed monthly based on an estimated fuel mix. This is then converted to a rate for customers based on the estimated MWh sales for the month. An efficiency factor (MBtu/kWh) is used to calculate the conversion between the MBtu of fuel purchased and the amount of kWhs generated. The ECAC is updated monthly and an Energy Cost Adjustment ("ECA") factor is determined on a prospective basis. A reconciliation is done on a quarterly basis, which compares revenues recovered through the ECAC and revenues allowed using actual fuel mix, kWh sales and prices. The overcollection or undercollection is adjusted in the ECA factor for the following three months. The monthly ECAC filings with the Hawaii Public Utility Commission ("Commission" or "HPUC") ensures timely recovery of fuel and purchased energy costs for HECO.

Act 162 is concerned specifically with the incentive structure facing utilities. Just as it is important for utilities to have incentives to control—to the extent they can—fuel and purchased power costs, so too should ratepayers have a cost-based price signal. Ratepayers will not choose to consume an efficient level of electricity it they are shielded from the true costs of producing electricity and a timely FAC therefore has an important role to play. When consumers are aware of, and can respond to, the cost effects of their energy consumption decisions, they can reduce their demand when the price outweighs the benefit of consuming the product. The efficient allocation of resources concerns the price signals faced by customers. Failure to allow rates to reflect fuel and purchased power costs in a timely manner would distort this efficiency, since customers would be receiving an inappropriate price signal regarding the value in the market of the services they choose to consume.

II. COMPLIANCE WITH ACT 162

Act 162 incorporates five requirements for the design of any public utility automatic rate adjustment.

A. Fair Risk Sharing of Fuel Cost Changes

Act 162 requires that any automatic rate adjustment be designed to "[f]airly share the risk of fuel cost changes between the public utility and its customers." The risk of fuel cost changes is determined by:

1. Changes in the price of fuel as a single productive input; and,

2. Changes in the cost to deliver and produce electricity from HECO's fuel inputs. This reflects any changes in the technical ability of the utility to turn fuel purchased into electricity, which may require HECO to purchase a greater quantity of fuel, and thus increase the overall level of fuel costs, in order to produce the same amount of electricity.

Efficient risk sharing occurs when the party that has the means to control a cost has an incentive to do so. This distinction is critical because the price of fuel is, realistically, beyond the control of the utility. HECO acts as a price taker in the world-wide market for fuel (oil) and the design of the ECAC and the recovery of fuel and purchased energy costs should recognize this fact.

Accordingly, the ECAC acts to pass exogenous changes in input costs onto consumers. In fuel markets (as in other markets where HECO is a price taker—as in vehicles), it is straightforward to demonstrate prudent purchasing. There is a well defined market price and a well defined need to buy from this market (i.e., ratepayers' demand for electricity). In a price-taking market, "risk sharing" of fuel price changes would lead to no efficiency gains resulting from management incentives to minimize costs. Accordingly, changes in the price of fuel should be fully passed onto ratepayers. This would provide them with a price signal, which is an incentive to use resources efficiently. This supports the utility's ability to maintain its financial viability, and would increase regulatory lag—the time between rate cases—for costs that are within the utility's control, which would enhance the utility's incentive to control its base rate costs.

The ECAC, with its "heat rate" efficiency factor, provides a partial pass through of fuel and purchased power. It shares the risk/benefit of increased plant operating efficiency by tying HECO's ability to recover its fuel costs (and thus its financial performance) to its power plant performance over which it has managerial control, while also allowing HECO to pass through the exogenous changes in the price of an input over which it has no control, the price of fuel and purchased power.

HECO has considerable control over the operation of its plants—limited by engineering realities—and therefore it is reasonable, as the Commission already does, to provide HECO with an incentive to improve its operating efficiency to manage or lower its fuel costs. As discussed in the next section, putting fuel oil expense recovery at risk in an attempt to give the Company an incentive to look for non fuel oil resources would be an inefficient, indirect and counterproductive way of subsidizing renewables. Directly subsidizing renewables or enforcing renewable portfolio standards will increase the usage of renewable generation resources, but without having the perverse effect of harming the utility's financial position or distorting the cost recovery mechanism to favor one fuel cost over another.

The general role that management plays in an investor-owned, regulated enterprise should be recognized. Efficient and prudent management strives to minimize the amount of inputs while maximizing the production of the final product (*i.e.*, to maximize total factor productivity). Viewed from this perspective, management should have an incentive to manage efficiently the selection of inputs (of which fuel and purchased power are two of many)—and HECO does have this incentive.

This heat rate efficiency factor properly shares the risk of fuel usage decisions and recognizes that the added risk of cost recovery associated with plant operation is balanced with rewards from productivity increases.

State commissions in Florida, Louisiana, and North Carolina are examples of jurisdictions that have established specific incentives for power plant performance. A "Generating Performance Incentive Factor" is included in fuel and purchased power recovery clauses in Florida that rewards the utility (up to a 25 basis point spread) when its generation assets achieve certain performance benchmarks in availability and heat rate. In North Carolina, the allowed level of fuel cost recovery is linked to achieved nuclear capacity factors. These are reasonable approaches that provide the utility incentives to improve plant performance, something over which it has considerable control.

Because the ECAC contains an efficiency factor that transfers plant operation risk to HECO, but also passes uncontrollable changes in fuel prices to ratepayers, NERA concludes that the ECAC complies with the fair risk sharing requirement of Act 162.

B. Utility Incentives for Fuel Costs and Renewable Energy

Act 162 requires that automatic rate adjustment mechanisms "[p]rovide the public utility with sufficient incentive to reasonably manage or lower its fuel costs and encourage greater use of renewable energy." This condition is closely tied to the previous one. Accordingly, the targeted efficiency factor promotes productive fuel use decisions and gives HECO an incentive to reasonably manage or lower its fuel costs.

If HECO achieves more efficient plant performance than the level of the efficiency factor (which, for example, is currently set at 0.11170 Mbtu/kWh), then HECO is rewarded. If it fails to meet this target for some reason, then it is not allowed to recover the additional expenditures required to produce the kWhs with the fuel it purchased.

The ECAC should cover all purchased energy costs, including renewable sources, on an equal footing within the cost recovery mechanism. Renewable energy resources can be part of a utility's power procurement to the extent that they are cost-efficient, reliable and represent a diverse source of generation relative to the traditional non-renewable resources. Like many utilities, HECO creates and follows an Integrated Resource Plan ("IRP"), which determines the extent of renewables used in HECO's fuel mix. The IRP process balances cost-minimization with resource diversity and other concerns. Like purchasing fuel oil from the oil markets, purchasing energy from renewables is not without risks. To ensure the efficient use of renewable resources, the ECAC would cover all purchased energy costs, including renewable sources, on an equal footing. Currently, the ECAC is adjusted each month for changes in the energy mix of the sources of fuel and purchased power. Under an equal footing structure, there is no disincentive from a cost recovery standpoint to purchase renewable energy. The encouragement of renewable energy above and beyond a treatment paralleling non-renewables (*i.e.*, direct subsidization) is a matter of public policy and should not be confused with energy cost recovery. The ECAC should provide no disincentive for HECO to purchase energy from renewable resources.[2]

The ECAC has positive financial implications and can improve a utility's credit ratings, thereby moderating the cost of capital borne by ratepayers. In addition, the utility serves as a counter-party for renewable energy companies, so its credit standing frequently serves as an important determinant of the financial viability of renewable energy projects. Weakening the utility's credit rating through partial power cost recovery could harm renewable resources that rely on utility counter-party credit to support their investments. Through the ECAC, HECO can retain its high level of credit worthiness and as party to renewable IPPS, which essential for IPP financing. By improving utility finances, the ECAC, in turn, accommodates renewable energy investors.

NERA concludes that a fuel adjustment clause with an efficiency target incentive that recovers renewable energy costs on an equal footing, such as the ECAC, complies with the incentive requirement of Act 162.

C. Management of Price Volatility

Thirdly, Act 162 requires automatic rate adjustments "to mitigate the risk of sudden or frequent fuel cost changes that cannot otherwise reasonably be mitigated through other commercially available means, such as fuel hedging contracts."

There are no free lunches in risk management. Hedging imposes real costs to the party that wishes to reduce its exposure to price movements. Although in years that prices rise, ratepayers may benefit from a price hedge, this will not be the case when prices do not rise or fall. In the long run, hedging programs can be expected to increase the overall level of costs associated with fuel and purchased power expenses. Accordingly, if there is a mandate for the utility to reduce

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[2] Including the capital costs associated with capacity purchases, such as renewable capacity purchases, in the ECAC (or a tracker mechanism that could operate in parallel with the ECAC) would be one way to ensure immediate cost recovery and thereby reduce any economic disincentive.

ratepayers' exposure to the potential rise in fuel costs, these hedging costs should be passed onto ratepayers.

Act 162 recognizes that there are options "commercially available" to customers that can mitigate price risk for customers. In principle, a utility can mitigate the risk of fuel cost changes through two forms of hedges:

1. *Physical hedges*, such as long-term supply and purchased power contracts and maintaining fuel inventories. The costs of existing contracts are included in the current ECAC computations.

2. *Financial hedges*. Generally, financial hedges either require payment to intermediaries in cash to bear risks or otherwise pay through giving up the prospect for lower future fuel prices. If utility ratepayers are willing to pay for the additional service of hedging their price risk, HECO must be provided a means to recover the costs it incurs. In order to do this and to give HECO a proper incentive to mitigate price changes on behalf of its customers, the ECAC would include recovery of financial hedging costs. Currently, the ECAC allows the recovery of the unhedged fuel costs, but is unclear whether financial hedging costs would be recovered in the ECAC.

In order to meet the electricity demands of its customers, HECO operates oil-fired power plants. HECO purchases the oil for these plants. HECO's position in oil is therefore a short physical position. HECO hedges its short physical position by entering into an offsetting long position in delivered oil. This long position is achieved through the companies' existing fuel supply contracts. These fuel supply contracts tie the price paid by HECO for oil to a base component. The base component is the month-to-date average of a third-party assessment calculated on the 20th of the month before delivery. For example, HECO's industrial fuel oil deliveries for January 2007 will be based on the average of the Platts Los Angeles Bunker C assessments from November 21st to December 20th 2006. The actual contract price includes taxes and a standard premium (based on quantity). Depending on the contract, the price may include a locational premium and adjustments for heat content, premia to Pertamina,[3] quality differentials and freight. In addition, the contracts provide for quantities and delivery of fuel that are more than sufficient to cover HECOs needs. Hence, HECO and HECO's customers are hedged with respect to availability and delivery of the physical commodities. HECO's fuel costs are variable as the price it pays will vary with the daily assessments for the terms of HECO's fuel contracts.

With respect to price, despite the fact that the price varies with assessment values, HECO is hedged from the perspective of the utility. HECO's physical fuel supply contracts are struck at floating assessments. Similarly, its electricity rates float in accordance with the prices of oil that HECO pays. As discussed earlier, this is a logical regulatory framework, since HECO has no

[3] The premia represent market premiums (or discounts) achieved in the spot market relative to a price assessment called the Pertamina Price Formula for LSWR.

control over world oil prices. The matching of variable fuel operating expenses with variable electricity revenues helps to assure the financial integrity of the utility, while providing an economically-correct price signal to customers.

The fuel hedging contracts referred to by the Act, if reasonably available, would only be entered into by HECO to meet the objective of mitigating oil price fluctuations for customers. Customers are exposed to fluctuations in world oil prices, while hedged against availability and physical delivery risks and costs. If HECO were to hedge, it would be to reduce this exposure. Of course, there would be a cost to reducing the exposure that may not be justified by the benefit. It should be noted that there are other alternatives (described in **Section IV**) available that may provide the similar benefits sought through hedging programs (*e.g.*, rate stability and reduced exposure to input cost increases), but would not require pursuing these potentially costly hedging options.

Therefore, NERA concludes that under HECO's current procurement strategies, the ECAC complies with the price stabilization requirement of Act 162. However, if there were demand from customers and/or a mandate from the Commission acting on behalf of ratepayers for a hedging program seeking to stabilize fuel costs, then recovery of the hedging and risk premium costs associated with physical and financial hedges would be included in the ECAC.[4]

D. Preservation of Utility Financial Integrity

The fourth requirement imposed by Act 162 on automatic rate adjustments is to "[p]reserve, to the extent reasonably possible, the public utility's financial integrity."

For modern utilities that operate in a world of volatile fuel prices an FAC is critical to:

- Reduce the volatility of utility earnings. Companies exhibiting large earnings volatility are typically those with most difficulty in tracking input costs.

- Provide the utility with a reasonable opportunity to recover its prudently-incurred costs in rates.

- Lower the risks to capital invested in a utility and thus lower the utility's cost of capital (and ultimately, rates) as well as help maintain the utility's credit rating. Volatile wholesale power and oil and gas commodity markets have led the rating agencies to more closely

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[4] At least 12 states (Alabama, Florida, Georgia, Louisiana, Iowa, Missouri, Mississippi, Minnesota, North Dakota, South Dakota, Nevada, Colorado and Michigan) allow the pass through of hedging costs and/or the sharing of hedging benefits between the utility and its customers, usually through their respective Power Cost Adjustments.

scrutinize cost-recovery mechanisms. Credit rating agencies, for example, recognize the need for robust and frequently updated FAC mechanisms.[5]

- Maintain HECO's liquidity. Because oil and other fuel expenses are a large portion of HECO's operational costs, the ECAC is needed to enable HECO to raise capital in time to meet expenses and investment requirements.

Utility regulators have long recognized the crucial role that cost-recovery mechanisms play in allowing the utility an opportunity to recover its costs. FACs permit a utility to recover its costs and assure the capital markets that the company can meet its obligations to shareholders and bondholders. Colorado provides an example of its Commission balancing the concerns of utility and its customers. The Colorado PUC explained its long-term use of FAC mechanisms by stating that it established its FAC in order to permit rapid recovery of increased costs over which the utility has no control. The PUC recognized that, in the circumstances which existed at the time, unless increased fuel costs were passed through to customers expeditiously, the utility would undergo a serious erosion of earnings jeopardizing the its ability to provide service.[6]

When approving the Arizona Public Service Company's ("APS") proposed Power Supply Adjustor, the Arizona Corporation Commission stated "we agree that the use of an adjustor when fuel costs are volatile prevents a utility's financial condition from deteriorating" and that "an adjustor that works correctly, over time, reduces the volatility of a utility's earnings and the risk reduction can be reflected in the cost of equity in a rate case and result in lower rates."[7]

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[5] Each of the three major credit rating agencies recognize the importance of FAC mechanisms. *Fitch* states: "[i]n today's environment, the safest bonds in the utility industry may be those of vertically integrated utilities operating under commission-approved mechanisms to recoup prudently incurred power costs. Such companies typically operate in supportive regulatory environments which continue to feel the need for healthy reserve margins of generation."

S&P also notes that "[a]utomatic pass-through mechanisms that hold companies harmless from uncontrollable costs, such as fuel or foreign exchange effects, are viewed favorably."

Moody's concludes that: "Regulated vertically integrated utilities operating without regulatory recovery of potentially high electricity costs from spot-market purchases are equally vulnerable, particularly during periods of peak energy demand and/or supply shortages."

See: *Fitch*, "Procuring Power in California: A Potential Stranded Cost," September 7, 2000, p. 4.
Standard & Poor's, "Rating Methodology For Global Power Utilities," Standard & Poor's Infrastructure Finance, September 1998, p. 66.
Moody's, "Credit Implications of Power Supply Risk," July 2000, p. 3.

[6] Before the Public Utilities Commission of the State of Colorado, "In the Investigation of Electric Cost Adjustment Clauses For Regulated Electric Utilities," Docket No. 931-702E, Decision No. C95-248, February 6, 1995.

[7] Before the Arizona Public Corporation Commission, In the Matter of the Application of Arizona Public Service for Approval of Adjustment Mechanisms, Docket No. E-01345A-02-0403, Decision No. 66567, November 13, 2003, p. 5.

As a frequently updated, fully reconciled pass through mechanism for a large and volatile expense, the ECAC plays a critical role. Continuation of the ECAC would allow HECO to more readily raise capital in the future. This will improve its ability to meet future infrastructure needs and preserve the level of service demanded by its ratepayers and the Commission. HECO recognizes this fact when it states in its most recent 10-K that:

> Risks, uncertainties and other important factors that could cause actual results to differ materially from those in forward–looking statements and from historical results include, but are not limited to...fuel oil price changes, performance by suppliers of their fuel oil delivery obligations and the continued availability to the electric utilities of their energy cost adjustment clauses.

Because the ECAC provides a transparent, well-structured and consistently-applied cost recovery mechanism that contains an efficiency incentive that HECO's management can readily affect, NERA concludes that the ECAC complies with the financial integrity requirement of Act 162.

E. Minimize Regulatory Costs

The fifth and final requirement established by Act 162 is to "[m]inimize, to the extent possible, the public utility's need to apply for frequent applications for general rate increases to account for the changes to its fuel costs."

In general, FACs are designed to reduce regulatory costs by separating the volatility of fuel costs from the base rates. Calculations supporting the ECAC are submitted to the Hawaii PUC for review on a monthly basis. A number of states have similar monthly fuel clauses. Braulio Baez, the Chairman of the Florida Public Service Commission states in a Consumer Bulletin concerning fuel price adjustments:

> The action of removing fuel costs from base rates had the effect of reducing fluctuations in base rates. Both the utilities and their customers now had a better incentive to respond to fuel price changes. Because non-fuel expenditures are more stable than fuel expenditures, utilities were not only less likely to seek base rate adjustments, but any rising costs also provided the utility with a greater incentive to use other, less expensive fuels to generate electricity.[8]

The reduction of frequent base rate cases does not reduce the Commission's oversight of HECO's fuel and purchased power expenditures. Electricity FACs can allow for recovery of narrowly-defined categories of fossil fuel costs, nuclear fuel costs, purchased power, fuel transportation costs, and hedging costs among others.

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[8] Braulio L Baez, "Customer Bulletin," Florida Public Service Commission, April 2004.

To further minimize regulatory costs, regulators can see that any other cost category that meets the three criteria for an automatic rate adjustment discussed in the background section receive parallel treatment to those costs already included in the ECAC. Cost categories to consider including in the ECAC (or tracking in a separate adjustment clause):

- All fuel and purchased power costs,
- Purchased capacity,
- Hedging costs,
- Environmental compliance costs, and
- Any other costs specific to the jurisdiction.

The breadth of adjustment clauses are not limited to fuel and purchased power expenses. Rather, the ECAC or a similar adjustment mechanism can be implemented efficiently for broader categories of costs, which would help to assure that supply- and demand-side energy resources are treated symmetrically in the ratemaking process.

Uniformity across the utilities' ECACs reduces the administrative costs associated with using a FAC to recover fuel and purchased power costs. Treating the fuel and purchased energy cost recovery of one HECO subsidiary separately from another would require further and unnecessary utility and Commission resources devoted to the treatment of fuel and purchased power costs.

Therefore, because the ECAC allows HECO to readily recover in rates a significant and volatile cost over which its has little control, NERA concludes that the ECAC reduces HECO's need to file base rate cases and thus complies with the minimization of regulatory cost requirement of Act 162.

III. ASSESSMENT OF FUEL HEDGING OPTIONS

This section of the report addresses fuel hedging options available in the marketplace. It gives a general overview of the objectives of hedging, a description of available hedging strategies, a discussion of the oil derivatives market and potential implementation constraints facing HECO and its affiliates as they consider entering into a hedging program.

A. Objectives of Fuel Hedging

EEI defines hedging as "the attempt to eliminate at least a portion of the risk associated with owning an asset or having an obligation by acquiring an asset or obligation with offsetting risks."[9] Hedging can, in principle, allow a firm to offset and reduce risk. Act 162 raises the question of whether HECO should hedge by reference to "fuel hedging contracts" as a commercially available means to mitigate the risk of fuel price changes.[10] Hedging with respect to energy commodities can take two forms: (1) physical hedges, such as physical supply contracts and fuel inventories; and (2) financial hedges, such as fixed-price financially-settled futures contracts and financial options contracts. As described in **Section II.C**, HECO already engages in physical hedging.

In regulatory parlance and in many industries, the term hedging most often refers to short-term (less than two years in duration) activities. This is because forward markets offer liquid price hedging contracts covering delivery periods that often extend only for one or two years forward. For the oil derivatives markets,[11] price hedging contracts are only reasonably available for periods of up to twelve months. This means that hedging contracts, if pursued by HECO, could only mitigate the impacts of oil price changes on costs and rates for a defined period such as one quarter or potentially one year. Fuel hedging contracts cannot be expected to cover durations longer than this.

Long-term hedging – i.e., hedging for multi-year periods – is a possibility for HECO, but cannot reasonably be achieved through commercially available fuel hedging contracts. Long-term hedging for HECO could be done through diversification away from oil-based generation. This diversification would require investment in non-oil based generation capacity, either by rate-based generation or through long-term contracts with non-utility generators. In addition, another long-term hedge could conceivably be the purchase of oil reserves. However, utilities that have purchased fuel reserves have almost universally regretted the decision and eventually disposed of the reserves. It is not recommended that HECO seriously consider this option.

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[9] EEI Glossary of Electric Industry Terms, April 2005.

[10] Act 162, (g) (iii).

[11] Derivatives are a term used to describe financial instruments whose value is derived from the price of an underlying commodity. Hence, an oil price swap or call option is a derivative as its value is based on the price of oil, the underlying commodity.

Hedging is most often done to lock in a range of outcomes. But, hedging creates costs and risks. Hedging will not necessarily produce the lowest-cost outcome in any particular case—and will, overall, raise costs because of the costs of implementing the hedging program. For a buyer of fuel like HECO, hedging may be perceived as a bad decision in hindsight if the buyer locks in a price and then market prices decline. Similarly, hedging may be perceived as a good decision if market prices increase after the buyer places its hedges. The utility, the regulator, and interveners must understand the costs and risks of hedging before a utility decides or is directed by its regulators to embark on a hedging program.

There are certain situations where firms face business or financial risks that make hedging particularly important. For example, if prices for the firm's product will remain relatively fixed as a significant input cost varies, then hedging that input cost may be necessary to protect cash flows and maintain financial stability. This will be the case when the firm is more reliant on a specific commodity than the industry in general and changes in that commodity's price have a disproportionately strong impact on market prices. This could also be the case when industry competitive pressures are so severe that product prices cannot rapidly adjust to meet changes in input costs.

Hedging also makes sense for firms whose financial structures are highly leveraged or for firms whose liquidity is dependent upon commodity prices or price spreads. Examples of such situations in the electricity industry include:

- an unregulated generator using coal or renewable fuel may only be viable if oil and gas prices are high and may only build if hedged by a long term contract at a fixed price.
- an unregulated generator using gas or oil may only be viable if spark spreads are high and may want to hedge spark spreads through forward power sales.[12]
- retailers in deregulated electric markets who sign fixed price contracts with customers will need to hedge supply costs to avoid losses that could exceed their liquidity limits.

The need to hedge in these cases arises because the entity has assumed obligations – debt, a contractual obligation to a third party, or an expectation by investors of stable earnings – that can only be achieved if prices of input commodities or spreads between input commodities are within a certain range. Hedging allows those firms to assure that input prices are within a certain range.

[12] The spark spread represents the theoretical margin for a power plant. If a spark spread is a positive number, then the price of the power is higher than that of the fuel and the spread is profitable. If the spread is a negative number, the power is priced at less than the cost of fuel and is not profitable. The spread can be determined using the natural gas, coal, or heating oil futures contracts. Mathematically, Spark Spread (in $/MWh) = [Electricity Total Value - Fuel Total Value] / [Amount of Electricity Delivered]. See: New York Mercantile Exchange, Conversion Calculator: Spark Spreads, http://www.nymex.com/calc_spark.aspx (Accessed December 22, 2006).

The motivation for regulated utilities to hedge is different from the motivation of firms in competitive industries. Regulated utilities that manage their businesses prudently are entitled to stable cash flows as a result of the regulatory compact. Regulated utilities with highly variable fuel costs generally have fuel adjustment clauses in place that provide for timely and adequate recovery of costs.

Hedging by regulated utilities is oriented toward managing customer rates; its objective is to insulate customers from the price fluctuations in an underlying commodity. For example, some gas and power distribution utilities hedge the commodities they sell in order to provide a fixed- or near-fixed price to customers. Integrated utilities with generation may hedge fuel costs in order to reduce the impact of fuel price changes on rates.

Hedging programs are generally designed and implemented by utilities in collaboration with the commissions that regulate them. The utilities agree upon an objective with the regulator and then they clearly establish a program for achieving that objective. The need for a regulated entity to hedge is created by a specific and customer-focused objective. Therefore, it must involve considerable regulatory oversight and guidance.

B. Overview of Strategies Used By Buyers of Commodities

Buyers of commodities can use a number of different hedging strategies to manage short-term price risk. There are three products that are commonly used by buyers of commodities:

- Forward contracts.
- Call option contracts.
- Collars.

These are addressed in turn below.

1. Forward or Futures Contracts

A forward contract is an agreement between two parties to buy or sell an asset or commodity at a pre-agreed future point in time. A standardized forward contract that is traded on an exchange is called a futures contract. Forward contracts are in most cases struck at fixed prices. A fixed-price forward contract locks in the price of the underlying commodity for both the buyer and seller.

Basis risks are the price risks that a buyer would be exposed to if the buyer cannot find a forward contract for the specific commodity it needs at the delivery location it needs. If the marketplace does not offer forward contracts that exactly match the commodity and the location where the buyer takes delivery, the buyer may purchase derivatives for a different commodity whose price is highly correlated with the product the buyer wishes to hedge. In addition, the buyer could purchase the same commodity it needs but at a delivery location other than the one where it takes delivery. In these cases, the buyer faces the risk associated with changes in the difference in prices between the two commodities or the two locations. The changes in these price differences are termed basis risk. Forward contracts are not readily available for the oil products and delivery locations that HECO needs, which means that if HECO decides to hedge, it will be exposed to basis risk.

A fixed-for-floating swap is also akin to a forward contract. A fixed-for-floating swap is a contract between two parties under which one party agrees to swap a fixed price for a published index price on a notional quantity. A fixed-for-floating swap is economically equivalent to a fixed-price forward contract. The difference is that the fixed-for-floating swap is a purely financial instrument, while a forward contract generally anticipates physical delivery.

2. Call Option Contracts

A call option gives its owner the right, but not the obligation, to buy an asset or commodity on a specified date (the expiration date), for a specified price (the strike price). Call options cap the price that will be paid by a buyer for a commodity.

3. Collars

A collar is a portfolio of options that is used to assure that the price of a commodity is within a given range. A buyer of a commodity who wishes to put a cap and floor on the price paid would sell a put option and buy a call option. This strategy assures that the price of the commodity will be within a given range – i.e., no lower than the strike price of the put (the floor) and no higher than the strike price of the call (the cap).

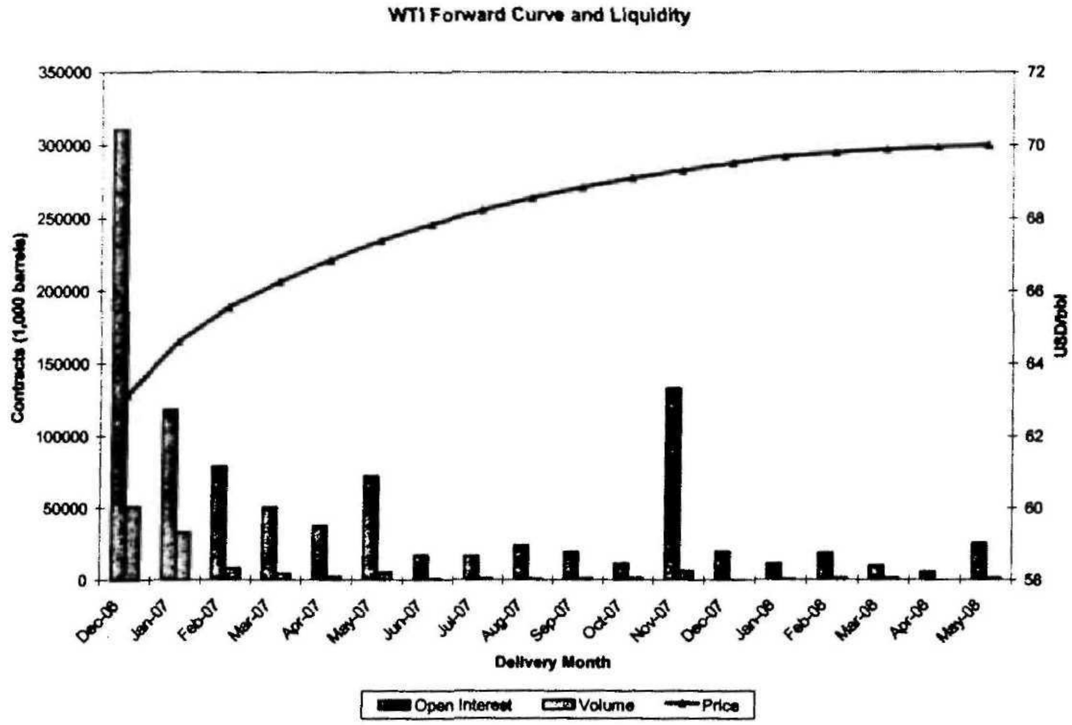
C. Characteristics of Oil Derivatives Markets

While the strategies outlined above work well in theory, they do not account for some of the practical considerations that must be considered with respect to implementing a hedging strategy. There are a number of practical implementation constraints that complicate hedging for HECO and its affiliates. These constraints are described below.

1. Duration of Derivatives

The first important constraint relates to the duration of the hedge. The forward and futures contracts that are traded in the marketplace do not reasonably extend beyond a term of 12 months. While there may be some quotes, the markets are quite illiquid beyond 18 months. Further, the most liquid (i.e., readily-available to trade) fuel hedging contracts are contracts that cover time periods of up to six months into the future. This is illustrated in **Figure 1** below.

Figure 1. Forward Curve and Liquidity in Oil Markets

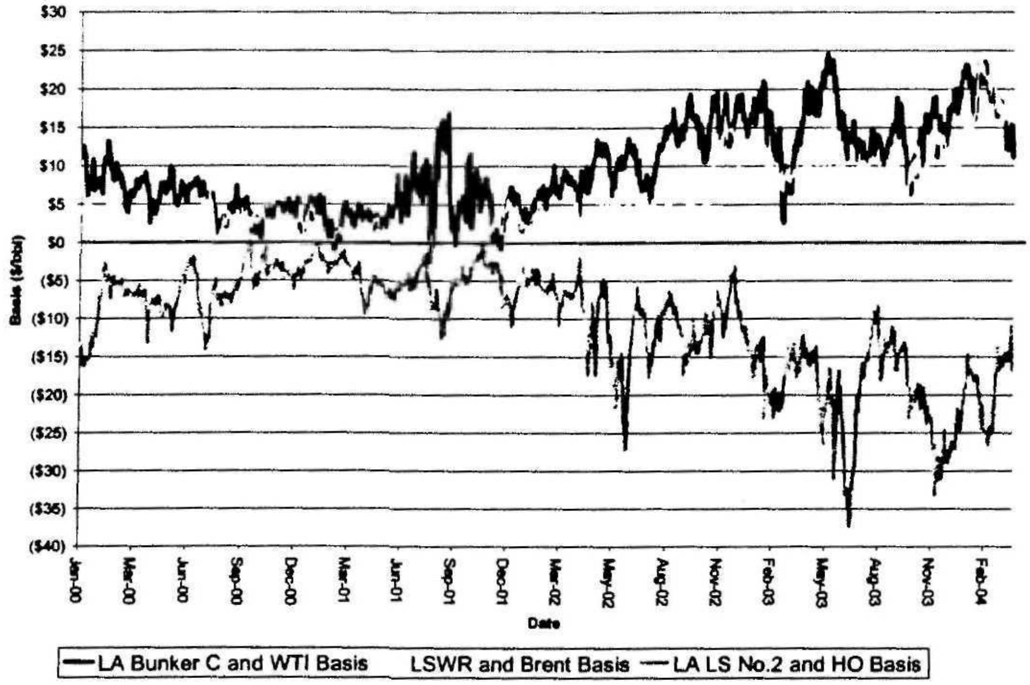


Notes: -The other fuel oils used by HECO (Heating Oil and Brent Crude Oil) display similar characteristics;
-Data as of November 30, 2006.

2. Delivery Points & Basis Risk

The second constraint faced by HECO and its affiliates is that hedging contracts for the precise oil products and delivery points that they would need are not visible in the marketplace. HECO would therefore be exposed to considerable basis risks if it used the oil derivatives that are readily-available in the marketplace. It is possible that a customized swap agreement could be obtained that hedges the price of the specific oil products in the specific locations that HECO and its affiliates need. However, such a swap is less transparent and it can be expected to be more expensive because the seller of such a swap would need to be remunerated for absorbing the basis risks and illiquidity of offering such a hedge. **Figure 2** illustrates the historical size of basis risks between the oil products that HECO and its affiliates use relative to spot prices of oil products for which HECO could obtain liquid hedges.

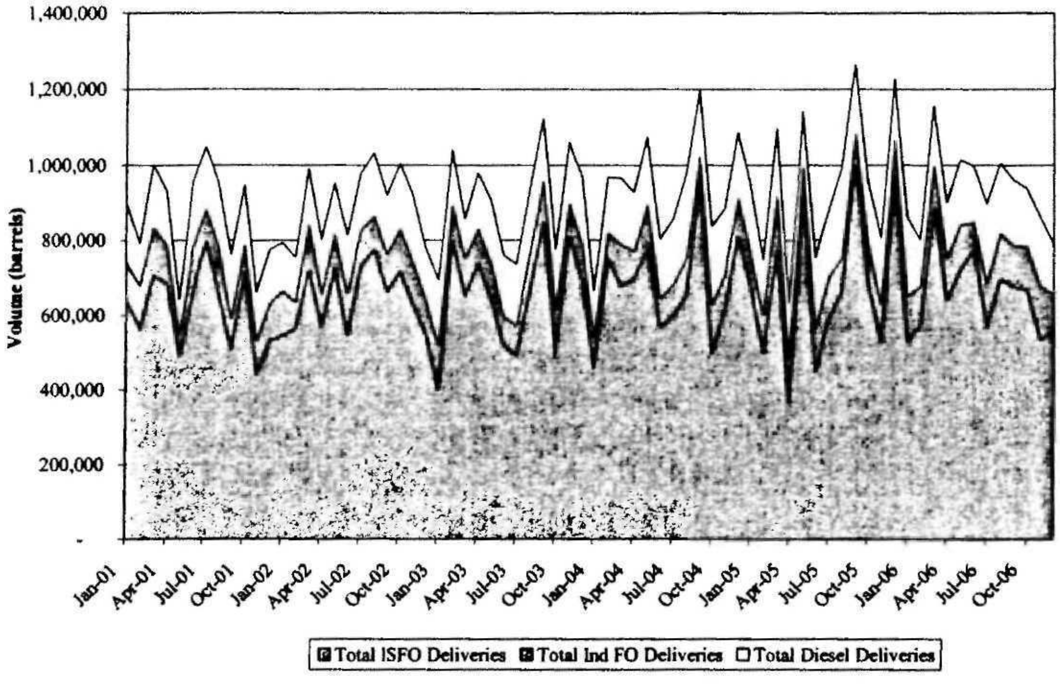
Figure 2. Daily Basis Risk for Heating Oil, WTI and Brent Fuels



3. Quantity Risk

The third constraint faced by HECO and its affiliates is the quantity they would hedge. The quantities that the utilities need of each type of fuel fluctuate month to month and year to year in accordance with changing demand, availability and relative economics of a generation plant, among other factors (as shown in **Figure 3**). The Utilities' existing fuel contracts provide for flexibility on the quantities taken, subject to a minimum and maximum take. The quantity flexibility embedded in the existing fuel contracts would be difficult to match in the financial derivatives markets, which offer fixed quantity products. If the utilities were to hedge the minimum expected quantity, their customers would face market risk exposure for incremental quantities, while hedging the maximum expected quantity would result in market risk exposure for decremental quantities. This quantity risk is important and makes accurate hedging difficult.

Figure 3. Quantity Risk: HECO's Monthly Deliveries of Fuel Oil Products



D. Implementation Issues

1. Credit Risks

If HECO and its affiliates decide to engage in hedging, they may face credit risk. Credit risk is the risk of a financial loss associated with the failure of a party to perform on its obligations under a hedging contract. Credit risk is an important factor when considering fuel hedging contracts. Market practice is to mark forward contracts to market and to collateralize the credit exposure embedded in forward contracts. This means that the value of the contract is calculated every day and any exposure must be covered as margin. If the utilities engage in hedging, counterparties may require that HECO and its affiliates provide collateral. The provision of collateral would add to the cost of hedging. Further, the utilities would, in most instances, be exposed to the risk of counterparty default and non-performance.

2. Liquidity Risks

The execution of fuel hedging contracts would expose HECO and its affiliates to liquidity risks. Liquidity is the ability to execute transactions in the marketplace. Markets that are highly liquid have active trading and many buyers and sellers. Market liquidity for oil derivatives ebbs and flows. When the markets are less liquid, a buyer or seller may face difficulties entering into or exiting positions. This is important because HECO or an affiliate may be forced to replace a position as a result of counterparty default. It is also important because it affects the price paid. In less liquid markets, it is more difficult for a buyer to get a good price. The risk that the markets HECO needs access to in order to execute or unwind and replace its hedge positions would not be liquid is a real one.

3. *Ex Post* Price Risk and Regulatory Scrutiny

It is not possible to predict the outcome of a particular hedging strategy before the fact. The ex post outcome will depend, to a large extent, on the price path of the underlying commodity during the hedging period. For example, assume that HECO fully hedges its fuel need with futures contracts at $40/bbl. No matter what happens to the price of oil from this point on, HECO will pay $40/bbl for oil. However, even though the initial hedge may have been perfectly rational *ex ante*, subsequent decreases in the price of oil will increase costs relative to a no-hedging strategy and increases in the price of oil will decrease costs relative to a no-hedging strategy. All hedging instruments contain similar risks relative to their respective strike prices. As the price of fuel oil changes, a prudent and reasonably managed hedging program implemented by HECO may become costly relative to another hedging strategy (including the strategy of not hedging at all).[13]

Like all potential costs and benefits to the utilities and their ratepayers, the risk of regulatory disallowance should be fully understood and examined prior to embarking on a hedging program. **Table 1** summarizes all of the costs and risks facing a utility implementing a hedging program.

[13] For an in depth treatment of this issue, see: Jeff D. Makholm, Eugene T. Meehan, and Julia E. Sullivan, "Ex Ante or Ex Post? Risk, Hedging and Prudence in the Restructured Power Business," *The Electricity Journal*, April 2006, Vol. 19, Issue 3, pp. 11-29.

Table 1. Costs and Risks of Hedging Programs

Administrative costs	• Corporate governance of hedging activities • Risk assessment and control • Cost of collateral postings • Compliance with hedge accounting rules • Up-front regulatory costs (cost of establishing hedging objective and hedging program including execution timeframe, contract types, contract duration) • Ongoing regulatory costs of hedging proceedings
Market risks	• Market risks on incremental/decremental quantities • Basis spread widens or contracts, thus reducing the effectiveness of the hedge
Credit risks	• Counterparty default risk
Liquidity risks	• Ability to unwind or replace positions
Duration of hedge	• Increase in market, credit and liquidity risks for long-dated hedges
Regulatory Risk	• Risk of hedging cost disallowances of a prudent *ex ante* hedging strategy that became costly.

E. Summary of Available Hedging Alternatives and Recommendations

It may be possible for HECO to hedge price risk for periods of up to 12 months into the future and, in the process, potentially provide customers with reduced (but not eliminated) exposure to sudden fuel cost changes. The process of executing hedges, setting rates based on the hedge costs, and informing customers of those rates would take time and the development of some level of expertise and sophistication on the part of HECO. Price hedging should not be expected to address rate periods more than one year at a time, nor should it be expected to insulate customers from long-term changes in the supply and demand for the resources used to produce electricity. Further, HECO could not reasonably hedge to eliminate all exposure to fuel cost fluctuations due to the multiple risks described above.

Were HECO to hedge, it would encounter periods during which it experienced gains on its hedges and other periods during which it experienced losses. The gains in large part would be offset by increased fuel purchase costs and the losses offset in large part by reduced fuel purchase costs. The ECAC framework would need to be revised so that the difference between the hedging gains and the increased fuel costs and the difference between the hedging losses and the reduced fuel costs were reflected in rates through the ECAC. This would cause HECO's fuel costs to fluctuate, but theoretically they would fluctuate to a lesser extent than they otherwise would. Hedging by HECO would not be expected to reduce fuel and purchased power costs and, in the long run, would be expected to increase the overall level of costs.

There are alternative mechanisms for achieving customer rate stability that could be more effective than hedging. Given the costs and risks of hedging described above, HECO and its affiliates could consider these options as an alternative to embarking on a fuel price hedging program. These alternatives will be discussed in the next section.

IV. ALTERNATIVES TO HEDGING

There is no compelling reason for HECO to use fuel price hedging as the means to achieve the goals of short-term customer rate stability and efficient fuel and power procurement practices. Two rate smoothing mechanisms will be discussed as potential alternatives to hedging programs. In addition, we will discuss the inclusion of power cost sharing conditions in traditional FAC mechanisms.

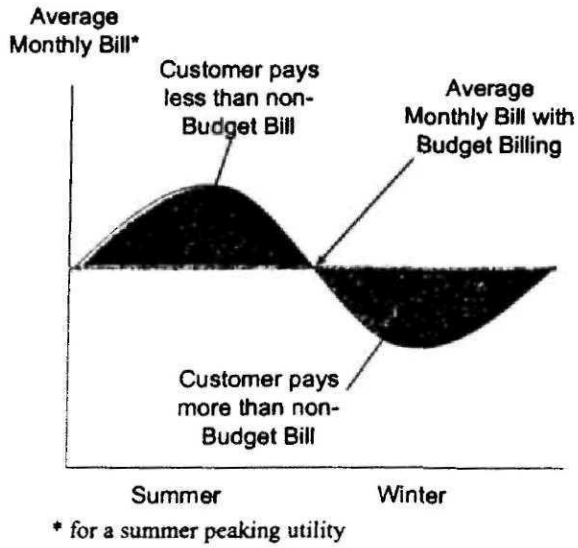
A. Rate Smoothing Mechanisms

This section presents an overview of two alternative rate smoothing ratemaking methods that could be used to provide customers with more stable rates in the short term, and in one case, temporarily limit customers' exposure to unexpected rises in fuel costs.

1. Budget Billing Rates

Budget billing is an "optional" payment program that allows the customer to pay the same amount each month for electricity or natural gas usage throughout the entire year. The voluntary nature of these programs limits any negative consumer feedback and targets the program to the consumers that want it. A monthly bill based upon previous usage patterns is estimated for the upcoming year as shown in **Figure 4**. At the end of the year, there is a true-up between the amount paid by the ratepayer and the amount the ratepayer would have paid, given his actual usage, under a non-budget billing rate plan.

Figure 4. Budget Billing Example



* for a summer peaking utility

Budget billing is typically offered to residential and small commercial customers as part of a plan to manage volatile changes in monthly energy costs, usually to seasonal changes in consumption. It should be noted that budget billing does nothing to mitigate rising electricity costs. Participants still pay the full amount for electricity, only the timing of payments over the course of the year is adjusted. Most states currently have a form of budget billing program available to residential customers.[14]

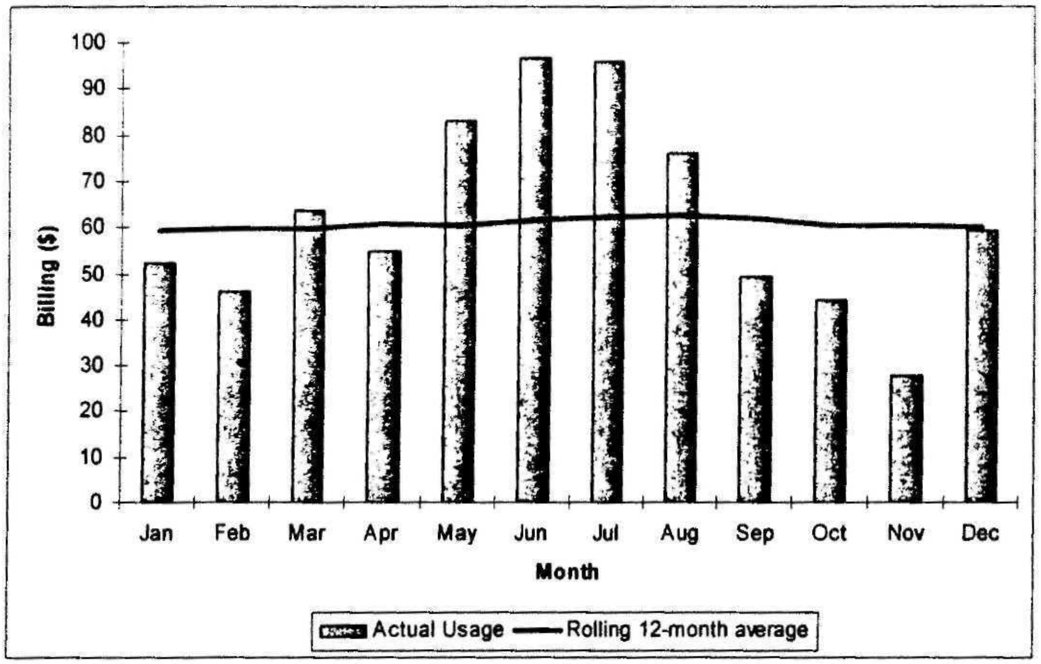
Budget billing has variations. For instance, NSTAR calculates its budget billing in the following fashion:

- Provides an equal payment from month to month based on usage for the previous year.
- At the end of the 12-month period, the Company reconciles any over or under usage from the estimate with the customer and sets the per-month payment for the next year.
- Reconciliation occurs in August/September time period each year.

An alternative to NSTAR's equal payment over a 12 month period is FPL's rolling average calculation for its budget billing. FPL calculates the bill for the current month by averaging the bills for the previous twelve months. As shown in **Figure 5**, this method results in slightly more volatility than NSTAR's equal payment plan, but allows the Company to recover their costs in a more timely fashion. The customer may also experience less true-up at the end of the period.

[14] In our survey, evidence of some form of budget billing was found in 47 U.S. states and the District of Columbia. Only Hawaii, Alaska and Rhode Island did not have a budget billing program.

Figure 5. Rolling 12-Month Average Budget Billing Example



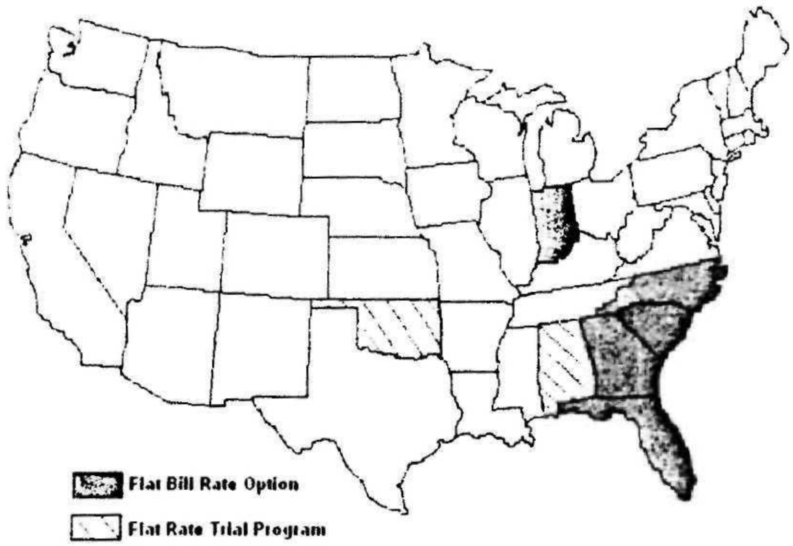
Source: Based on FPL's illustration found at: http://www.fpl.com/pay/contents/budget_billing.shtml (Accessed December 19, 2006).

The need for a budget billing plan in Hawaii may not be as large as most continental U.S. states due to the relative mild seasonality in demand. Nevertheless, budget billing may serve to aid low-income customers achieve rate stability, while perhaps helping the Company to decrease its uncollectible expenses.

2. Fixed Rate / Flat Bill Options

Some states have allowed utilities to have a rate option called "fixed rate" or "flat bill" in which a customer pays the same bill each month with no periodic reconciliation or true-up. The rates charged under these programs include risk premiums to reflect the risk the utility assumes by offering these programs. Fixed rate billing programs are generally available for larger commercial and industrial users who value (and are willing to pay for) insulation from unexpected price increases. **Figure 6** shows the states that have implemented flat bill rate options and trial programs.

Figure 6. Flat Bill Programs



Source: Michael O'Sheasy, "The Fixed Bill: Newborn Becomes Toddler!" January 4, 2005, http://topics.energycentral.com/centers/billing/view/detail.cfm?aid=900 (Accessed December 19, 2006).

Fixed rate billing is a voluntary rate option, which can help to identify customers that value rate stability. Voluntary rate plans can raise a whole host of issues, since customers will tend to switch to the plan that they find most advantageous. These issues include adverse selection, moral hazard and rate rebalancing issues.[15] In the case of fixed rate options, adverse selection and moral hazard problems may mean that only those customers who will alter their behavior to take advantage of the fixed rate nature of the program (*i.e.*, increase consumption without the risk of electricity price spikes) will be the customers that enroll. This was seen in Gulf Power's trial program where "Gulf noted that bills were adjusted by a 3.9 percent consumption adder only. The results of the pilot program showed an actual increase in kWh usage of 8 percent."[16]

[15] Adverse selection and moral hazard are economic problems that result from incomplete or asymmetric information. When buyers and sellers have asymmetric information, trades actually completed may be biased to favor the party with better information. Adverse selection typically refers to information asymmetry that exists prior to the transaction and leads to a selection bias in the group participating in the activity. Moral hazard refers to information asymmetry that occurs after the transaction occurs. For example, insurance coverage may affect the behavior of the insured to undertake activities and risks that may change the likelihood of incurring losses.

[16] Florida Public Service Commission, Memorandum, Re: Docket No. 040442-EI – Petition for authority to implement proposed FlatBill rate schedule by Gulf Power Company, September 23, 2004, p. 6. http://www.psc.state.fl.us/agendas/041005cc/04100516.html (Accessed December 27, 2006).

The revenue neutrality of the rate design (or rate rebalancing) is achieved through proper construction of the fixed rate premium. However, designing a balanced optional tariff depends on many parameters, such as the actual size of the program, the size of any premiums and the behavior of the program's participants, many of which are not known and can only be estimated prior to the program.

A risk premium is necessary because fixed rate billing present costs and risks to the utility, leading it to incur additional costs. If fuel and purchased power prices are higher than expected, fixed rate billing will under-collect. The opposite is also true. Therefore, fixed rate billing effectively forces the utility to take a position in the underlying commodity market; therefore, the utility may make the business decision to hedge this exposure to the commodity markets. The costs of this hedging as well as any additional costs, such as any administrative costs and costs associated with any expected increase in demand by these customers, would necessarily be included in the fixed rate premium.

Fixed rate programs would offer a utility the ability to limit the risks typically associated with hedging fuel costs by limiting the program to those customers willing to pay for a price-hedged product. When evaluating Gulf Power's proposed fixed rate program, the Florida Public Service Commission ("FL PSC") discussed the magnitude of a risk adder:

> Gulf has indicated that two of the factors used to calculate a customer's FlatBill rate will be a risk adder and a consumption adder. The adders account for various types of risk that Gulf has identified in offering a customer the level bill...The proposed permanent program utilizes both a consumption adder and a risk adder. The risk adder recognizes that actual usage and response may differ from what Gulf expected. The risk adder reflects three sources of risk: modeling risk, weather risk, and price risk. Gulf estimated a 5% risk premium based on their Value-at-Risk methodology. This methodology requires as inputs an aggregate risk measure, which is based on the variability of the three sources of risk, and a cost of capital input...[The Commission recommended that] the consumption adder applied to the customer's forecasted annual usage [shall] not exceed eight percent (8%) and the risk adder, used to account for financial, weather, and other risks [shall] not exceed five percent (5%).[17]

Further, the FL PSC discussed how Gulf Power's fixed rate program can impact the utility's revenue requirement and profitability:

> Under the FlatBill program proposal, Gulf intends to determine the amount of revenues for earnings surveillance and other regulatory purposes by using the actual energy usage of the FlatBill customer and multiplying that actual energy usage by the otherwise applicable tariff rate including the appropriate cost

[17] *Id.*, pp. 6-9.

> recovery factors. The difference between the actual FlatBill revenues and the calculated "otherwise applicable" revenues would be *excluded for all regulatory purposes*. In other words, any FlatBill revenues in excess of the otherwise applicable revenues would flow to Gulf's shareholders. Conversely, the shareholders would absorb any loss if the FlatBill revenues were less than the otherwise applicable revenues.[18]

Ultimately, fixed rate billing provides benefits to larger customers similar to budget billing (rate stability) with the added benefit of insulation from input cost increases. Rates will, on average be higher for the customers who select this option.

B. "Risk Sharing" Mechanisms

Act 162 recognizes the impact an automatic rate adjustment can have on utilities and requires that a FAC provide a utility with an incentive to minimize – to the extent it can – fuel costs. As discussed earlier, the ECAC achieves this goal through the efficiency parameter, which is a targeted measurement of utility plant performance. Some states, however, have adopted partial pass-through mechanisms. Note that these are some times referred to as "risk sharing" mechanisms, but that characterization is incorrect given that a utility is a price taker, and would not be able to control the price of fuel and purchased power acquired from the market. **Table 2** provides a brief overview of these mechanisms.

[18] *Id.*, p. 9. (emphasis added)

Table 2. State Experience with Partial Pass Through Mechanisms

State (Utility)	Mechanism
Arizona (Arizona Public Service)	90 percent of any costs or savings relative to the base level would be allocated to customers and 10 percent is allocated to the company.
Colorado (Public Service Co. of Colorado)	Graduated sharing mechanism relative to a base level: The first $15 million is allocated 50/50. The next $15 million is allocated 75/25 between ratepayers and the utility, respectively. Any changes above $30 million are to be recovered from or flowed back to ratepayers. The maximum profit or loss that PSCO will absorb is $11.25 million in any one year.
Idaho (Idaho Power)	The power cost adjustment is 90 percent of the difference between the projected power cost and the base power cost plus the true-ups.
Washington (Puget Sound Energy)	Graduated sharing mechanism: PSE will absorb the first $20 million relative to the baseline, 50% of the next $20 million, 10% of the next $80 million, and 5% of any amount that exceeds $120 million. The Washington Commission also implemented a "power-cost-only rate case," so PSE can update its baseline rate to reflect changing power costs.
Washington (Avista)	Originally, the first $9 million is absorbed by the company (an $18 million deadband) and 90 percent of the energy cost differences exceeding the initial $9 million to be deferred for a later rebate or surcharge to customers. The parameters were modified in July 2006 to a $4 million deadband, a 50/50 sharing of energy cost differences between $4 million and $10 million and a 90/10 sharing of power costs in excess of $10 million.

These jurisdictions blur the distinction between risk sharing for productive purposes and risk sharing in the price-taking purchase of inputs. In other words, some jurisdictions impose risk sharing on the price of fuel and purchased power.

These cases are idiosyncratic and have generally represented a broad movement toward less risk imposed on the utilities involved in fuel and power purchases. In Arizona, FACs were suspended in 1989, but APS established a new one in a settlement to its 2003 rate case. Thus, APS went from no pass through to 90 percent pass through of fuel and purchased power costs. In Colorado, Public Service Company of Colorado ("PSCO") has other adjustment clauses for DSM costs, air quality improvement costs and purchased capacity that may compensate the utility for the increased fuel and purchased power risks. In its current rate case, PSCO extended its use of its fuel adjustment clause, but was also granted two associated incentive mechanisms: (1) if PSCO achieves coal production greater than a benchmark target, the associated savings would be shared 80/20 with customers; and (2) PSCO would share 80 percent of savings (above a deadband) related to the purchase of economic short term energy. In Idaho, Idaho Power absorbed all fuel cost changes prior to 1993, 40 percent from 1993 to 1995, and only 10 percent thereafter. Still, major deferrals occurred during Western Power Crisis (for later collection after contentious base rate proceedings). The story in Washington follows similar lines. Neither utility had a FAC and power costs were recoverable through base rate cases. Recent variations in hydroelectric generation supply (due to a seven year drought) increased the size of deferrals and threatened the utilities' finances. Avista filed a petition on January 30, 2006, proposing to eliminate the $18 million deadband of their Energy Recovery Mechanism ("ERM"). In a settlement, Avista's deadband was narrowed to $8 million ($4 million above and below the base level) with a 50/50 sharing of power costs between $4 million and $10 million and a 90/10 sharing of power costs starting at $10 million above or below the base level. The settlement also called on Avista to examine the cost of capital impact of the ERM, as well as the company's hedging strategy for fuel and wholesale power purchases. This represents another movement towards full pass through of power costs.

The fuel mix and thus exposure (and risk) to oil market price risk of the above utilities are also dramatically different than HECO, which relies heavily upon oil for its generation needs. **Table 3** shows that oil plays an insignificant role in these utilities' generation mix and its fuel and purchased power costs. Their large hydro, nuclear and coal resources mitigate much of their exposure to the volatile oil and natural gas markets.

Table 3. Fuel Mix for Utilities / States with Partial Pass Through Mechanisms

Fuel Type / Source	HECO[1]	APS[2]	PSCO[3]	Idaho[4]	Washington[5]
Hydro	0.5%	0.0%	0.0%	46.0%	66.0%
Coal	14.3%	39.3%	45.0%	47.0%	17.7%
Nuclear	0.0%	22.6%	10.0%	0.0%	5.3%
Gas	0.0%	9.1%	38.0%	6.0%	9.5%
Oil	79.3%	9.1%	0.0%	0.0%	0.1%
Renewables / other	5.9%	19.7%	7.0%	1.0%	1.4%
Total	100.0%	100.0%	100.0%	100.0%	100.0%

Sources:

[1] HECO website, About Our Fuel Mix, http://www.heco.com/portal/site/heco/menuitem.508576f78baa14340b4c0610c510b1ca/?vgnextoid=047a5e658e0fc010VgnVCM1000008119fea9RCRD&vgnextchannel=deeaf2b154da9010VgnVCM10000053011bacRCRD&vgnextfmt=default&vgnextrefresh=1&level=0&ct=article (Accessed on December 12, 2006).

[2] Arizona Public Service, Generation Fuel Mix and Emission Characteristics, http://www.aps.com/_files/services/BusRates/disclosure.pdf (Accessed on December 18, 2006). Note that APS does not distinguish between gas and oil. They report that gas/oil comprises 18.2% of generation, for illustrative purposes this was split 50/50.

[3] Xcel Energy Fuel Supply Sources, http://library.corporate-ir.net/library/89/894/89458/items/223379/12_6XcelUtilityWeekSECwAppendix12062006.pdf (Accessed on December 18, 2006)

[4] Generation Options for Idaho's Energy Plan, presentation to the Subcommittee on Generation Resources, August 10, 2006, http://www.legislature.idaho.gov/sessioninfo/2006/Interim/energy_e3_0810.ppt#561,31,2005 Idaho Electricity Fuel Mix (Accessed on December 12, 2006).

[5] State of Washington, Department of Community, Trade and Economic Development, Fuel Mix Disclosure, http://www.cted.wa.gov/site/539/default.aspx (Accessed on December 12, 2006).

A fuel efficiency factor is an incentive targeted at a utility's production decisions and isolates the utility's production performance directly. Partial pass through mechanisms are relatively rare, and have been adopted for utilities with no existing FAC in place. They should not be considered a viable option for fair risk sharing of fuel and purchased energy costs in Hawaii.

Fuel prices constitute a large and volatile cost for price taking utilities. A well established, frequently updated FAC is essential to maintain a utility's credit and operational viability. Partial pass through mechanisms that defer power cost recovery in an attempt to shield ratepayers from power cost changes present an inefficient solution to the rate stability issues and the rising cost of electricity input costs. Forcing a utility to temporarily absorb a portion of power cost changes (assuming that the utility can defer the recovery of costs not passed through a FAC to a future rate case) does not prevent consumers from ultimately having to pay the full amount for their power usage, and may harm the utility's financial position.

V. CONCLUSIONS

NERA's conclusions can be summarized as follows.

1. The ECAC framework that is currently in place for HECO and its affiliates is compliant with Act 162, but the eligible costs would need to be broadened if HECO were to engage in hedging using financial hedge products.

2. Short-term price hedging by HECO and its affiliates is possible in the oil derivatives market, but such activities would not eliminate fuel price fluctuations because ratepayers would continue to be exposed to basis risks, hedge quantity risks and other risks. In addition, hedging in the oil derivatives market would introduce new costs and risks for ratepayers. Fuel price hedging in oil derivatives markets is not, therefore, a compelling way to achieve the objective of customer rate stability.

3. Rate smoothing, in the form of budget billing or flat bills, is an alternative mechanism for achieving customer rate stability that could achieve the objective at a lower expected cost. NERA recommends that HECO and its affiliates consider rate smoothing in more detail.

Sharing of the risk of oil price fluctuations between customers and shareholders is not good regulatory policy when the utility has no control over world oil markets. Such sharing would not exempt consumers from ultimately having to pay the full amount for their power usage, (assuming that the utility can defer the recovery of costs not passed through a FAC to a future rate case) and thereby harm the utility's financial position.

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CERTIFICATE OF SERVICE

I hereby certify that on December 29, 2006, I served copies of the foregoing Report on Power Cost Adjustments and Hedging Fuel Risks together with this Certificate of Service, by hand delivery or carrier to the following at the following addresses:

Division of Consumer Advocacy (4 copies)
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DATED: Honolulu, Hawaii, December 29, 2006.

Lyndon Haack

Lyndon Haack

DOD-IR-85

[Ref. DOD-IR-28]

a. Does Dr. Morin believe his texts are an original source of the DCF? If so, please explain why; if not, please explain why he offered only his texts in response to DOD-IR-28a.

b. Why is the DCF sometimes referred to as the Gordon model or the Gordon growth model?

c. Please provide a cite to the page(s) of Dr. Morin's 1984 text that indicates the DCF provides an accurate estimate of the cost of equity "only when stock price and book value are reasonably similar."

Dr. Morin's Response:

a. No. However, Dr. Morin does not recall any textbook that discusses the issue of return understatement (overstatement) when the market-to-book ratio exceeds (is less than) one.

b. The model is frequently referred to as the Gordon model, named after its inventor, Professor Myron Gordon, who in turn was greatly inspired by John Burr Williams. Dr. Morin does not recall any portion of Professor Gordon's seminal textbook that discusses the issue of return understatement (overstatement) when the market-to-book ratio exceeds (is less than) one.

c. The issue is fully discussed in the 1994 (Chapter 9) and 2006 (Chapter 15) versions of Dr. Morin's textbook when market-to-book ratios of utility stocks began to escalate well above one. There is no reference to M/B ratios in the 1984 book as this was not an issue in the early 1980s.

DOD-IR-86

[Ref. DOD-IR-33]

Please provide a complete copy of the Bruner article. Due to various office moves, the DOD cost of capital witness does not have access to prior responses by the Consumer Advocate in HECO's 2005 rate proceeding.

Dr. Morin's Response:

Please see pages 2 to 24 for HECO's response to CA-RIR-17 in Docket No. 04-0113 (HECO's 2005 Test Year Rate Case) filed on August 29, 2005.

CA-RIR-17
DOCKET NO. 04-0113
PAGE 2 OF 24

CASE 12

"Best Practices" in Estimating the Cost of Capital: Survey and Synthesis

In recent decades, theoretical breakthroughs in such areas as portfolio diversification, market efficiency, and asset pricing have converged into compelling recommendations about the cost of capital to a corporation. By the early 1990s, a consensus had emerged prompting such descriptions as "traditional . . . textbook . . . appropriate," "theoretically correct" and "a useful rule of thumb and a good vehicle."[1] Beneath this general agreement about cost of capital theory lies considerable ambiguity and confusion over how the theory can best be applied. The issues at stake are sufficiently important that differing choices on a few key elements can lead to wide disparities in estimated capital cost. The cost of capital is central to modern finance touching on investment and divestment decisions, measures of economic profit, performance appraisal and incentive systems. Each year in the United States, corporations undertake more than $500 billion in capital spending. Since a difference of a few percent in capital costs can mean a swing in billions of expenditures, how firms estimate the cost is no trivial matter.

The purpose of this paper is to present evidence on how some of the most financially sophisticated companies and financial advisers estimate capital costs. This evidence is valuable in several respects. First, it identifies the most important ambiguities in the application of cost-of-capital theory, setting the stage for productive debate and research on their resolution. Second, it helps interested companies benchmark their cost-of-capital estimation

[1]The three sets of quotes come, in order, from Ehrhardt (1994), Chapter 1; Copeland et al. (1990), p. 190; and Brealey and Myers (1993), p. 197.

This chapter was written by Robert F. Bruner, Kenneth M. Eades, Robert S. Harris, and Robert C. Higgins. Bruner, Eades, and Harris are professors at the Darden School, University of Virginia. Higgins is a professor at the University of Washington. The authors thank Todd Brotherson for excellent research assistance, and gratefully acknowledge the financial support of Coopers & Lybrand and the University of Virginia Darden School Foundation. The research would not have been possible without the cooperation of the 37 companies surveyed. These contributions notwithstanding, any errors remain the authors'. This chapter appeared in *Journal of Financial Practice and Education* (Spring 1998), and appears here with the permission of the Financial Management Association International, University of South Florida, College of Business Administration, Tampa, FL 33620-5500 (telephone: 813-974-2084).

CA-RIR-17
DOCKET NO. 04-0113
PAGE 3 OF 24

practices against best-practice peers. Third, the evidence sheds light on the accuracy with which capital costs can be reasonably estimated, enabling executives to use the estimates more wisely in their decision making. Fourth, it enables teachers to answer the inevitable question, "How do companies really estimate their cost of capital?"

The paper is part of a lengthy tradition of surveys of industry practice. Among the more relevant predecessors, Gitman and Forrester (1977) explored "the level of sophistication in capital budgeting techniques" among 103 large, rapidly growing businesses, finding that the internal rate of return and the payback period were in common use. Although the authors inquired about the level of the firm's discount rate, they did not ask how the rate was determined. Gitman and Mercurio (1982) surveyed 177 Fortune 1000 firms about "current practice in cost of capital measurement and utilization," concluding that "the respondents' actions do not reflect the application of current financial theory." Moore and Reichert (1983) surveyed 298 Fortune 500 firms on the use of a broad array of financial techniques, concluding among other things, that 86 percent of firms surveyed use time-adjusted capital budgeting techniques. Bierman (1993) surveyed 74 Fortune 100 companies reporting that all use some form of discounting in their capital budgeting and 93 percent use a weighted-average cost of capital. In a broad-ranging survey of 84 Fortune 500 large firms and Forbes 200 best small companies, Trahan and Gitman (1995) report that 30 percent of respondents use the capital asset pricing model.

This paper differs from its predecessors in several important respects. Existing published evidence is based on written, closed-end surveys sent to a large sample of firms, often covering a wide array of topics and commonly using multiple-choice or fill-in-the-blank questions. Such an approach often yields response rates as low as 20 percent and provides no opportunity to explore subtleties of the topic. Instead, we report the result of a telephone survey of a carefully chosen group of leading corporations and financial advisers. Another important difference is that the intent of existing papers is most often to learn how well accepted modern financial techniques are among practitioners, while we are interested in those areas of cost-of-capital estimation where finance theory is silent or ambiguous and practitioners are left to their own devices.

The following section gives a brief overview of the weighted-average cost of capital. The research approach and sample selection are discussed in Section II. Section III reports the general survey results. Key points of disparity are reviewed in Section IV. Section V discusses further survey results on risk adjustment to a baseline cost of capital, and Section VI offers conclusions and implications for the financial practitioner.

I. THE WEIGHTED-AVERAGE COST OF CAPITAL

A key insight from finance theory is that any use of capital imposes an opportunity cost on investors; namely, funds are diverted from earning a return on the next best equal-risk investment. Since investors have access to a host of financial market opportunities, corporate uses of capital must be benchmarked against these capital market alternatives. The cost of capital provides this benchmark. Unless a firm can earn in excess of its cost of capital, it will not create economic profit or value for investors.

A standard means of expressing a company's cost of capital is the weighted average of the cost of individual sources of capital employed. In symbols, a company's weighted-average cost of capital (or WACC) is

$$\text{WACC} = (W_{\text{debt}}(1 - t)K_{\text{debt}}) + (W_{\text{preferred}}K_{\text{preferred}}) + (W_{\text{equity}}K_{\text{equity}}) \qquad (1)$$

where:

K = Component cost of capital
W = Weight of each component as percent of total capital
t = Marginal corporate tax rate

For simplicity, this formula includes only three sources of capital; it can be easily expanded to include other sources as well.

Finance theory offers several important observations when estimating a company's WACC. First, the capital costs appearing in the equation should be current costs reflecting current financial market conditions, not historical, sunk costs. In essence, the costs should equal the investors' anticipated internal rate of return on future cash flows associated with each form of capital. Second, the weights appearing in the equation should be market weights, not historical weights based on often arbitrary, out-of-date book values. Third, the cost of debt should be after corporate tax, reflecting the benefits of the tax deductibility of interest.

Despite the guidance provided by finance theory, use of the weighted-average expression to estimate a company's cost of capital still confronts the practitioner with a number of difficult choices.[2] As our survey results demonstrate, the most nettlesome component of WACC estimation is the cost of equity capital; for unlike readily available yields in bond markets, no observable counterpart exists for equities. This forces practitioners to rely on more abstract and indirect methods to estimate the cost of equity capital.

II. SAMPLE SELECTION

This paper describes the results of a telephone survey of leading practitioners. Believing that the complexity of the subject does not lend itself to a written questionnaire, we wanted to solicit an explanation of each firm's approach told in the practitioner's own words. Though our interviews were guided by a series of questions, these were sufficiently open-ended to reveal many subtle differences in practice.

Since our focus is on the gaps between theory and application rather than on average or typical practice, we aimed to sample practitioners who were leaders in the field. We began by searching for a sample of corporations (rather than investors or financial advisers) in the belief that they had ample motivation to compute WACC carefully and

[2]Even at the theoretical level, Dixit and Pindyck (1994) point out that the use of standard net present value (NPV) decision rules (with, for instance, WACC as a discount rate) does not capture the option value of being able to delay an irreversible investment expenditure. As a result, a firm may find it better to delay an investment even if the current NPV is positive. Our survey does not explore the ways firms deal with this issue; rather we focus on measuring capital costs.

CA-RIR-17
DOCKET NO. 04-0113
PAGE 5 OF 24

to resolve many of the estimation issues themselves. Several publications offer lists of firms that are well regarded in finance;[3] of these, we chose a research report, *Creating World-Class Financial Management: Strategies of 50 Leading Companies* (1992), which identified firms,

> selected by their peers as being among those with the best financial management. Firms were chosen for excellence in strategic financial risk management, tax and accounting, performance evaluation and other areas of financial management. . . . The companies included were those that were mentioned the greatest number of times by their peers.[4]

From the 50 companies identified in this report, we eliminated 18 headquartered outside North America.[5] Of those remaining, five declined to be interviewed, leaving a sample of 27 firms. The companies included in the sample are given in **Exhibit 1.** We approached the most senior financial officer first with a letter explaining our research, and then with a telephone call. Our request was to interview the individual in charge of estimating the firm's WACC. We promised our interviewees that, in preparing a report on our findings, we would not identify the practices of any particular company by name—we have respected this promise in the presentation that follows.

In the interest of assessing the practices of the broader community of finance practitioners, we surveyed two other samples:

- *Financial advisers.* Using a "league table" of merger and acquisition advisers presented in *Institutional Investor* issues of April 1995, 1994, and 1993, we drew a sample of 10 of the most active[6] advisers. We applied approximately[7] the same set of questions to representatives of these firms' merger and acquisition departments. We wondered whether the financial advisers' interest in promoting deals might lead them to lower WACC estimates than those estimated by operating companies. This proved not to be the case. If anything, the estimating techniques most often used by financial advisers yield higher, not lower, capital cost estimates.
- *Textbooks and trade books.* From a leading textbook publisher we obtained a list of the graduate-level textbooks in corporate finance having the greatest unit sales in 1994. From

[3]For instance, *Institutional Investor* and *Euromoney* publish lists of firms with the best CFOs, or with special competencies in certain areas. We elected not to use these lists because special competencies might not indicate a generally excellent finance department, nor might a stellar CFO.

[4]*Creating World-Class Financial Management: Strategies of 50 Leading Companies*, Research Report No. I-110, Business International Corporation, New York, 1992 (238 pages), pages vii–viii. This survey was based upon a written questionnaire sent to CEOs, CFOs, controllers, and treasurers, followed up by a telephone survey.

[5]Our reasons for excluding these firms were the increased difficulty of obtaining interviews, and possible difficulties in obtaining capital market information (such as betas and equity market premiums) that might preclude using American practices. The enlargement of this survey to firms from other countries is a subject worthy of future study.

[6]*Activity* in this case was defined as four-year aggregate deal volume in mergers and acquisitions. The sample was drawn from the top 12 advisers, using their *average* deal volume over the 1993–95 period. Of these 12 firms, 2 chose not to participate in the survey.

[7]Specific questions differ, reflecting that financial advisers infrequently deal with capital budgeting matters and that corporate financial officers infrequently value companies.

these, we selected the top four. In addition, we drew on three trade books that discuss the estimation of WACC in detail.

Names of advisers and books included in these two samples are shown in Exhibit 1.

III. SURVEY FINDINGS

The detailed survey results appear in Exhibit 2. The estimation approaches are broadly similar across the three samples in several dimensions:

- Discounted cash flow (DCF) is the dominant investment-evaluation technique.
- WACC is the dominant discount rate used in DCF analyses.
- Weights are based on *market*, not book, value mixes of debt and equity.[8]
- The after-tax cost of debt is predominantly based on *marginal* pretax costs, and *marginal* or *statutory* tax rates.
- The capital asset pricing model (CAPM) is the dominant model for estimating the cost of equity. Some firms mentioned other multifactor asset pricing models (e.g., arbitrage pricing theory), but these were in the small minority. No firms cited specific modifications of the CAPM to adjust for any empirical shortcomings of the model in explaining past returns.[9]

These practices differ sharply from those reported in earlier surveys.[10] First, the best-practice firms show much more alignment on most elements of practice. Second, they base their practice on financial economic models rather than on rules of thumb or arbitrary decision rules.

On the other hand, disagreements exist within and among groups on how to apply the CAPM to estimate cost of equity. The CAPM states that the required return (K) on any asset can be expressed as

$$K = R_f + \beta(R_m - R_f) \qquad (2)$$

where:

R_f = Interest rate available on a risk-free bond
R_m = Return required to attract investors to hold the broad market portfolio of risky assets
β = the relative risk of the particular asset

[8]The choice between target and actual proportions is not a simple one. Because debt and equity costs clearly depend on the proportions of each employed, it might appear that the actual proportions must be used. However, if the firm's target weights are publicly known and if investors expect the firm soon to move to these weights, then observed costs of debt and equity may anticipate the target capital structure.

[9]For instance, even research supporting the CAPM has found that empirical data are better explained by an intercept higher than a risk-free rate and a price of beta risk less than the market risk premium. Ibbotson (1994) offers such a modified CAPM, in addition to the standard CAPM and other models, in its cost of capital service. Jagannathan and McGrattan (1995) provide a useful review of empirical evidence on the CAPM.

[10]Gitman and Forrester (1977), and Gitman and Mercurio (1982).

According to CAPM, then, the cost of equity, K_{equity}, for a company depends on three components: returns on risk-free bonds (R_f); the stock's equity beta, which measures risk of the company's stock relative to other risky assets ($\beta = 1.0$ is average risk); and the market risk premium ($R_m - R_f$) necessary to entice investors to hold risky assets generally versus risk-free bonds. In theory, each of these components must be a forward-looking estimate. Our survey results show substantial disagreements on all three components.

Comments on Risk-Free Rates

Some of our best-practice companies noted that their choice of a bond market proxy for a risk-free rate depended specifically on how they were proposing to spend funds. We asked, "What do you use for a risk-free rate?" and heard the following:

- "Ten-year Treasury bond or other duration Treasury bond if needed to better match project horizon."
- "We use a three- to five-year Treasury note yield, which is the typical length of our company's investment. We match our average investment horizon with maturity of debt."

The Risk-Free Rate of Return

As originally derived, the CAPM is a single-period model, so the question of which interest rate best represents the risk-free rate never arises. But in a many-period world typically characterized by upward-sloping yield curves, the practitioner must choose. Our results show the choice is typically between the 90-day T-bill yield and a long-term Treasury bond yield. (Because the yield curve is ordinarily relatively flat beyond 10 years, the choice of which particular long-term yield to use is not a critical one.)[11] The difference between realized returns on the 90-day T-bill and the 10-year T-bond has averaged 150 basis points over the long run; so choice of a risk-free rate can have a material effect on the cost of equity and WACC.[12]

The 90-day T-bill yields are more consistent with the CAPM as originally derived and reflect truly risk-free returns in the sense that T-bill investors avoid material loss in value from interest rate movements. However, long-term bond yields more closely reflect the

[11] In early January 1996, the differences between yields on the 10- and 30-year T-bonds was about 35 basis points. Some aficionados will argue that there *is* a difference between the 10- and 30-year yields. Ordinarily the yield curve declines just slightly as it reaches the 30-year maturity—this has been explained to us as the result of life insurance companies and other long-term buy-and-hold investors who are said to purchase the long bond in significant volume. It is said that these investors command a lower liquidity premium than the broader market, thus driving down yields. If this is true, then the yields at this point of the curve may be due not to some ordinary process of rational expectations, but rather to an anomalous supply–demand imbalance, which would render these yields less trustworthy. The counterargument is that life insurance companies could be presumed to be rational investors too. As buy-and-hold investors, they will surely suffer the consequences of any irrationality and therefore have good motive to invest for yields "at the market."

[12] This was estimated as the difference in arithmetic mean returns on long-term government bonds and U.S. Treasury bills over the years 1926 to 1994, given in Ibbotson Associates (1995).

default-free holding period returns available on long-lived investments and thus more closely mirror the types of investments made by companies.

Our survey results reveal a strong preference on the part of practitioners for long-term bond yields. Of both corporations and financial advisers, 70 percent use Treasury-bond yield maturities of 10 years or greater. None of the financial advisers and only 4 percent of the corporations used the Treasury-bill yield. Many corporations said they matched the term of the risk-free rate to the tenor of the investment. In contrast, 43 percent of the books advocated the T-bill yield, while only 29 percent used long-term Treasury yields.

Beta Estimates

Finance theory calls for a forward-looking beta, one reflecting investors' uncertainty about the future cash flows to equity. Because forward-looking betas are unobservable, practitioners are forced to rely on proxies of various kinds. Most often this involves using beta estimates derived from historical data and published by such sources as Bloomberg, Value Line, and Standard & Poor's.

The usual methodology is to estimate beta as the slope coefficient of the market model of returns:

$$R_{it} = \alpha_i + \beta_i(R_{mt}) \tag{3}$$

where:

R_{it} = Return on stock i in time period (e.g., day, week, month) t
R_{mt} = Return on the market portfolio in period t
α_i = Regression constant for stock i
β_i = Beta for stock i

In addition to relying on historical data, use of this equation to estimate beta requires a number of practical compromises, each of which can materially affect the results. For instance, increasing the number of time periods used in the estimation may improve the statistical reliability of the estimate, but risks the inclusion of stale, irrelevant information. Similarly, shortening the observation period from monthly to weekly, or even daily, increases the size of the sample but may yield observations that are not normally distributed and may introduce unwanted random noise. A third compromise involves choice of the market index. Theory dictates that R_m is the return on the market portfolio, an unobservable portfolio consisting of *all* risky assets, including human capital and other nontraded assets, in proportion to their importance in world wealth. Beta providers use a variety of stock market indices as proxies for the market portfolio on the argument that stock markets trade claims on a sufficiently wide array of assets to be adequate surrogates for the unobservable market portfolio.

The following table shows the compromises underlying the beta estimates of three prominent providers and their combined effect on the beta estimates of our sample companies. Note, for example, that the mean beta of our sample companies according to Bloomberg is 1.03, while the same number according to Value Line is 1.24. **Exhibit 3** provides a complete list of sample betas by publisher.

Compromises Underlying Beta Estimates and Their Effect on Estimated Betas of Sample Companies

	Bloomberg*	Value Line	Standard & Poor's
Number of observations	102	260	60
Time interval	Weekly over 2 years	Weekly over 5 years	Monthly over 5 years
Market index proxy	S&P 500	NYSE composite	S&P 500
Sample mean beta	1.03	1.24	1.18
Sample median beta	1.00	1.20	1.21

*With the Bloomberg service it is possible to estimate a beta over many differing time periods, market indices, and smoothed or unadjusted. The figures presented here represent the base-line or default-estimation approach used if one does not specify other approaches.

Over half of the corporations in our sample (item 10, Exhibit 2) rely on published sources for their beta estimates, although 30 percent calculate their own. Among financial advisers, 40 percent rely on published sources, 20 percent calculate their own, and another 40 percent use what might be called "fundamental" beta estimates. These are estimates which use multifactor statistical models drawing on fundamental indices of firm and industry risk to estimate company betas. The best-known provider of fundamental beta estimates is the consulting firm BARRA.

Within these broad categories, the following comments indicate that a number of survey participants use more pragmatic approaches, which combine published beta estimates or adjust published estimates in various heuristic ways.

We asked our sample companies, "What do you use as your volatility or beta factor?" A sampling of responses shows that the choice is not always a simple one:

- "[We use] adjusted betas reported by Bloomberg. At times, our stock has been extremely volatile. If at a particular time the factor is considered unreasonably high, we are apt to use a lower (more consistent) one."
- "We begin with the observed 60-month covariance between our stock and the market. We also consider Value Line, BARRA, S&P betas for comparison and may adjust the observed beta to match assessment of future risk."
- "We average Merrill Lynch and Value Line figures and use Bloomberg as a check."
- "We do not use betas estimated on our stock directly. Our company beta is built up as a weighted average of our business segment betas—the segment betas are estimated using pure-play firm betas of comparable companies."

Equity Market Risk Premium

This topic prompted the greatest variety of responses among survey participants. Finance theory says the equity market risk premium should equal the excess return expected by investors on the market portfolio relative to riskless assets. How one measures expected future returns on the market portfolio and on riskless assets are problems left to practitioners.

Because expected future returns are unobservable, all survey respondents extrapolated historical returns into the future on the presumption that past experience heavily conditions future expectations. Where respondents chiefly differed was in their use of *arithmetic* versus *geometric* average historical equity returns and in their choice of realized returns on T-bills versus T-bonds to proxy for the return on riskless assets.

The arithmetic mean return is the simple average of past returns. Assuming the distribution of returns is stable over time and that periodic returns are independent of one another, the arithmetic return is the best estimator of expected return.[13] The geometric mean return is the internal rate of return between a single outlay and one or more future receipts. It measures the compound rate of return investors earned over past periods. It accurately portrays historical investment experience. Unless returns are the same each time period, the geometric average will always be less than the arithmetic average and the gap widens as returns become more volatile.[14]

Based on Ibbotson Associates' (1995) data from 1926 to 1995, the matrix below illustrates the possible range of equity market risk premiums depending on use of the geometric as opposed to the arithmetic mean equity return and on use of realized returns on T-bills as opposed to T-bonds.[15] Even wider variations in market risk premiums can arise when one changes the historical period for averaging. Extending U.S. stock experience back to 1802, Siegel (1992) shows that historical market premiums have changed over time and were typically lower in the pre-1926 period. Carleton and Lakonishok (1985) illustrate considerable variation in historical premiums using different time periods and methods of calculation even with data since 1926.

The Equity Market Risk Premium ($R_m - R_f$)

	T-Bill Returns	T-Bond Returns
Arithmetic mean return	8.5%	7.0%
Geometric mean return	6.5%	5.4%

Of the texts and trade books in our survey, 71 percent support use of the arithmetic mean return over T-bills as the best surrogate for the equity market risk premium. For long-term projects, Ehrhardt advocates forecasting the T-bill rate and using a different cost of equity for each future time period. Kaplan and Ruback (1995) studied the equity risk premium implied by the valuations in highly leveraged transactions and estimated a mean pre-

[13]Several studies have documented significant negative autocorrelation in returns—this violates one of the essential tenets of the arithmetic calculation, since if returns are not serially independent, the simple arithmetic mean of a distribution will not be its expected value. The autocorrelation findings are reported by Fama and French (1986), Lo and MacKinlay (1988), and Poterba and Summers (1988).

[14]For large samples of returns the geometric average can be approximated as the arithmetic average minus one-half the variance of realized returns. Ignoring sample size adjustments, the variance of returns in the current example is .09 yielding an estimate of $.10 - 1/2(.09) = .055 = 5.5\%$ versus the actual 5.8% figure. Kritzman (1994) provides an interesting comparison of the two types of averages.

[15]These figures are drawn from Table 2-1, Ibbotson (1995), where the R_m was drawn from the "Large Company Stocks" series, and R_f drawn from the "Long-Term Government Bonds" and "U.S. Treasury Bills" series.

mium of 7.97 percent, which is most consistent with the arithmetic mean and T-bills. A minority view is that of Copeland, Koller, and Murrin (1990, pp. 193–94) writing on behalf of the Corporate Financial Practice at McKinsey & Company: "We believe that the geometric average represents a better estimate of investors' expected returns over long periods of time." Ehrhardt (1994) recommends use of the geometric mean return if one believes stockholders are "buy-and-hold" investors.

Half of the financial advisers queried use a premium consistent with the arithmetic mean and T-bill returns, and many specifically mentioned use of the arithmetic mean. Corporate respondents, on the other hand, evidenced more diversity of opinion and tend to favor a lower market premium: 37 percent use a premium of 5 to 6 percent, and another 11 percent use an even lower figure.

Comments Regarding Market Risk Premium

"What do you use as your market risk premium?" A sampling of responses from our best-practice companies shows the choice can be a complicated one.

- "Our 400-basis-point market premium is based on the historical relationship of returns on an actualized basis and/or investment bankers' estimated cost of equity based on analysts' earnings projections."
- "We use an Ibbotson arithmetic average starting in 1960. We have talked to investment banks and consulting firms with advice from 3 to 7 percent."
- "A 60-year average of about 5.7 percent. This number has been used for a long time in the company and is currently the subject of some debate and is under review. We may consider using a time horizon of less than 60 years to estimate this premium."
- "We are currently using 6 percent. In 1993 we polled various investment banks and academic studies on the issue as to the appropriate rate and got anywhere between 2 and 8 percent, but most were between 6 and 7.4 percent."

Comments from financial advisers also were revealing. While some simply responded that they use a published historical average, others presented a more complex picture.

- "We employ a self-estimated 5 percent (arithmetic average). A variety of techniques are used in estimation. We look at Ibbotson data and focus on more recent periods, around 30 years (but it is not a straight 30-year average). We use smoothing techniques, Monte Carlo simulation, and a dividend discount model on the S&P 400 to estimate what the premium should be, given our risk-free rate of return."
- "We use a 7.4 percent arithmetic mean, after Ibbotson, Sinquefeld. We used to use the geometric mean following the then scholarly advice, but we changed to the arithmetic mean when we found later that our competitors were using the arithmetic mean and scholars' views were shifting."

Comments in our interviews (see box above) suggest the diversity among survey participants. While most of our 27 sample companies appear to use a 60-plus-year historical period to estimate returns, one cited a window of less than 10 years, two cited windows of about 10 years, one began averaging with 1960 and another with 1952 data.

This variety of practice should not come as a surprise, since theory calls for a forward-looking risk premium, one that reflects current market sentiment and may change with market conditions. What is clear is that there is substantial variation as practitioners try to operationalize the theoretical call for a market risk premium. A glaring result is that few respondents specifically cited use of any forward-looking method to supplement or replace reading the tea leaves of past returns.[16]

IV. THE IMPACT OF VARIOUS ASSUMPTIONS FOR USING CAPM

To illustrate the effect of these various practices, we estimated the hypothetical cost of equity and WACC for Black & Decker, which we identified as having a wide range in estimated betas, and for McDonald's, which has a relatively narrow range. Our estimates are "hypothetical" in that we do not adopt any information supplied to us by the companies but rather apply a range of approaches based on publicly available information as of late 1995. *Exhibit 4* gives *Black & Decker's* estimated costs of equity and WACCs under various combinations of risk-free rate, beta, and market risk premiums. Three clusters of practice are illustrated, each in turn using three betas as provided by S&P, Value Line, and Bloomberg (unadjusted). The first approach, as suggested by some texts, marries a short-term risk-free rate (90-day T-bill yield) with Ibbotson's arithmetic mean (using T-bills) risk premium. The second, adopted by a number of financial advisers, uses a long-term risk-free rate (30-year T-bond yield) and a risk premium of 7.2 percent (the modal premium mentioned by financial advisers). The third approach also uses a long-term risk-free rate but adopts the modal premium mentioned by corporate respondents of 5.5 percent. We repeated these general procedures for McDonald's.

The resulting ranges of estimated WACCs for the two firms are as follows:

	Maximum WACC	Minimum WACC	Difference in Basis Points
Black & Decker	12.80%	8.50%	430
McDonald's	11.60%	9.30%	230

The range from minimum to maximum is large for both firms, and the economic impact is potentially stunning. To illustrate this, the present value of a level perpetual annual stream of $10 million would range between $78 million and $118 million for Black & Decker, and between $86 million and $108 million for McDonald's.

Given the positive but relatively flat slope of the yield curve in late 1995, most of the variation in our illustration is explained by beta and the equity market premium assumption. Variations can be even more dramatic, especially when the yield curve is inverted.

[16]Only two respondents (one advisor and one company) specifically cited forward-looking estimates, although others cited use of data from outside sources (e.g., a company using an estimate from an investment bank) where we cannot identify whether forward-looking estimates were used. Some studies using financial analyst forecasts in dividend growth models suggest market risk premiums average in the 6 to 6.5 percent range and change over time with higher premiums when interest rates decline. See for instance, Harris and Marston (1992). Ibbotson (1994) provides industry-specific cost-of-equity estimates using analysts' forecasts in a growth model.

V. RISK ADJUSTMENTS TO WACC

Finance theory is clear that a single WACC is appropriate only for investments of broadly comparable risk: A firm's overall WACC is a suitable benchmark for a firm's average risk investments. Finance theory goes on to say that such a company-specific figure should be adjusted for departures from such an average risk profile. Attracting capital requires payment of a premium that depends on risk.

We probed whether firms use a discount rate appropriate to the risks of the flows being valued in questions on types of investment (strategic vs. operational), terminal values, synergies, and multidivisional companies. Responses to these questions displayed in Exhibit 3 do not display much apparent alignment of practice. When financial advisers were asked how they value parts of multidivision firms, all 10 firms surveyed reported that they use different discount rates for component parts (item 17). However, only 26 percent of companies always adjust the cost of capital to reflect the risk of individual investment opportunities (item 12). Earlier studies (summarized in Gitman and Mercurio (1982) reported that between a third and a half of firms surveyed did *not* adjust for risk differences among capital projects. These practices stand in stark contrast to the recommendations of textbooks and trade books: The books did not explicitly address all subjects, but when they did, they were uniform in their advocacy of risk-adjusted discount rates.

A closer look at specific responses reveals the tensions as theory based on traded financial assets is adapted to decisions on investments in real assets. Inevitably, a fine line is drawn between use of financial market data versus managerial judgments. Responses from financial advisers illustrate this. As shown in Exhibit 2, all advisers use different capital costs for valuing parts (e.g., divisions) of a firm (item 17); only half ever select different rates for synergies or strategic opportunities (item 18); only 1 in 10 state any inclination to use different discount rates for terminal values and interim cash flows (item 16). Two simplistic interpretations are that (1) advisers ignore important risk differences or (2) material risk differences are rare in assessing factors such as terminal values. Neither of these fits; our conversations with advisers reveal that they recognize important risk differences but deal with them in a multitude of ways. Consider comments from two prominent investment banks who use different capital costs for valuing parts of multidivision firms. When asked about risk adjustments for prospective merger synergies, these same firms responded as follows:

- "We make these adjustments in cash flows and multiples rather than in discount rates."
- "Risk factors may be different for realizations of synergies, but we make adjustments to cash flows rather than the discount rate."

While financial advisers typically value existing companies, corporations face further challenges. They routinely must evaluate investments in new products and technologies. Moreover, they deal in an administrative setting that melds centralized (e.g., calculating a WACC) and decentralized (e.g., specific project appraisal) processes. As the next box of comments illustrates, these complexities lead to a blend of approaches for dealing with risk. A number of respondents mentioned specific rate adjustments to distinguish between divisional capital costs, international versus domestic investments, and leasing versus nonleasing situations. In other instances, however, these same respondents favored cash-flow adjustments to deal with risks.

Why do practitioners risk-adjust discount rates in one case and work with cash-flow adjustments in another? Our interpretation is that risk-adjusted discount rates are more likely used when the analyst can establish relatively objective financial market benchmarks for what rate adjustments should be. At the business (division) level, data on comparable companies provide cost-of-capital estimates. Debt markets provide surrogates for the risks in leasing cash flows. International financial markets shed insights on cross-country differences. When no such market benchmarks are available, practitioners look to other methods for dealing with risks. Lacking a good market analog from which to glean investor opinion (in the form of differing capital costs), the analyst is forced to rely more on internal focus. Practical implementation of risk-adjusted discount rates thus appears to depend on the ability to find traded financial assets that are comparable in risk to the cash flows being valued and then to have financial data on these traded assets.

Comments Regarding Adjustments for Project Risk

When asked whether they adjusted discount rates for project risk, companies provided a wide range of responses:

- "No, it's difficult to draw lines between the various businesses we invest in, and we also try as best we can to make adjustments for risk in cash-flow projections rather than in cost of capital factors. . . . We advocate minimizing adjustments to cost of capital calculations and maximizing understanding of all relevant issues (e.g., commodity costs and international/political risks)." At another point the same firm noted that "for lease analysis only the cost of debt is used."
- "No [we don't risk adjust cost of capital]. We believe there are two basic components: (1) projected cash flows, which should incorporate investment risk, and (2) discount rate." The same firm noted, however, "For international investments, the discount rate is adjusted for country risk." and "For large acquisitions, the company takes significantly greater care to estimate an accurate cost of capital."
- "No, but use divisional costs of capital to calculate a weighted average company cost of capital . . . for comparison and possible adjustment."
- "Yes, we have calculated a cost of capital for divisions based on pure play betas and also suggest subjective adjustments based on each project. Our feeling is that use of divisional costs is the most frequent distinction in the company."
- "Rarely, but at least on one occasion we have, for a whole new line of business."
- "We do sensitivity analysis on every project."
- "For the most part we make risk adjustments qualitatively; i.e., we use the corporate WACC to evaluate a project, but then interpret the result according to the risk of the proposal being studied. This could mean that a risky project will be rejected even though it meets the corporate hurdle rate objectives."
- "No domestically; yes internationally—we assess a risk premium per country and adjust the cost of capital accordingly."

The pragmatic bent of application also comes to the fore when companies are asked how often they reestimate capital costs (item 13, Exhibit 2). Even for those firms that reestimate relatively frequently, the next box of comments shows that they draw an important distinction between estimating capital costs and policy changes about the capital cost figure used in the firm's decision making.

Firms consider administrative costs in structuring their policies on capital costs. For a very large venture (e.g., an acquisition), capital costs may be revisited each time. On the other hand, only large material changes in costs may be fed into more formal project evaluation systems. Firms also recognize a certain ambiguity in any cost number and are willing to live with approximations. While the bond market reacts to minute basis-point changes in investor return requirements, investments in real assets, where the decision process itself is time-consuming and often decentralized, involve much less precision. To paraphrase one of our sample companies, we use capital costs as a rough yardstick rather than the last word in project evaluation.

Our interpretation is that the mixed responses to questions about risk adjusting and reestimating discount rates reflect an often sophisticated set of practical trade-offs; these involve the size of risk differences, the quality of information from financial markets, and the realities of administrative costs and processes. In cases where there are material differences in perceived risk, a sufficient scale of investment to justify the effort, no large scale administrative complexities, and readily identifiable information from financial markets, practitioners employ risk adjustments to rates quite routinely. Acquisitions, valuing divisions of companies, analysis of foreign versus domestic investments, and leasing versus nonleasing decisions were frequently cited examples. In contrast, when one or more of these factors is not present, practitioners are more likely to employ other means to deal with risks.

Comments Regarding Reestimating WACC

How frequently do you reestimate your company's cost of capital? Here are responses from best-practice companies:

- "We usually review it quarterly but would review more frequently if market rates changed enough to warrant the review. We would only announce a change in the rate if the recomputed number was materially different than the one currently being used."
- "We reestimate it once or twice a year, but we rarely change the number that the business units use for decision and planning purposes. We expect the actual rate to vary over time, but we also expect that average to be fairly constant over the business cycle. Thus, we tend to maintain a steady discount rate within the company over time."
- "Usually every six months, except in case of very large investments, in which it is reestimated for each analysis."
- "Whenever we need to, such as for an acquisition or big investment proposal."
- "Reevaluate as needed (e.g., for major tax changes), but unless the cost of capital change is significant (a jump to 21 percent, for instance), our cutoff rate is not changed; it is used as a *yardstick* rather than the last word in project evaluation."
- "Probably need a 100-basis-point change to publish a change. We report only to the nearest percent."

VI. CONCLUSIONS

Our research sought to identify the "best practice" in cost-of-capital estimation through interviews of leading corporations and financial advisers. Given the huge annual expenditure on capital projects and corporate acquisitions each year, the wise selection of discount rates is of material importance to senior corporate managers.

The survey revealed broad acceptance of the WACC as the basis for setting discount rates. In addition, the survey revealed general alignment in many aspects of the estimation of WACC. The main area of notable disagreement was in the details of implementing the capital asset pricing model (CAPM) to estimate the cost of equity. This paper outlined the varieties of practice in CAPM use, the arguments in favor of different approaches, and the practical implications.

In summary, we believe that the following elements represent "best current practice" in the estimation of WACC:

- Weights should be based on *market-value* mixes of debt and equity.
- The after-tax cost of debt should be estimated from *marginal* pretax costs, combined with *marginal* or *statutory* tax rates.
- CAPM is currently the preferred model for estimating the cost of equity.
- Betas are drawn substantially from published sources, preferring those betas using a long interval of equity returns. Where a number of statistical publishers disagree, best practice often involves judgment to estimate a beta.
- Risk-free rate should match the tenor of the cash flows being valued. For most capital projects and corporate acquisitions, the yield on the U.S. government Treasury bond of 10 or more years in maturity would be appropriate.
- Choice of an equity market risk premium is the subject of considerable controversy both as to its value and method of estimation. Most of our best-practice companies use a premium of 6 percent or lower, while many texts and financial advisers use higher figures.
- Monitoring for changes in WACC should be keyed to major changes in financial market conditions, but should be done at least annually. Actually flowing a change through a corporate system of project valuation and compensation targets must be done gingerly and only when there are material changes.
- WACC should be risk adjusted to reflect substantive differences among different businesses in a corporation. For instance, financial advisers generally find the corporate WACC to be inappropriate for valuing different parts of a corporation. Given publicly traded companies in different businesses, such risk adjustment involves only modest revision in the WACC and CAPM approaches already used. Corporations also cite the need to adjust capital costs across national boundaries. In situations where market proxies for a particular type of risk class are not available, best practice involves finding other means to account for risk differences.

Best practice is largely consistent with finance theory. Despite broad agreement at the theoretical level, however, there remain several problems in application that can lead to wide divergence in estimated capital costs. Based on these remaining problems, we believe that further applied research on two principal topics is warranted. First, practitioners need additional tools for sharpening their assessment of relative risk. The variation in company-specific beta estimates from different published sources can create large differences in capital cost estimates. Moreover, use of risk-adjusted discount rates appears limited by lack of good market proxies for different risk profiles. We believe that appropriate use of averages across industry or other risk categories is an avenue worth exploration. Second, practitioners could benefit from further research on estimating equity market risk premiums. Current practice displays large variations and focuses primarily on averaging past data. Use of expectational data appears to be a fruitful approach. As the next generation of theories gradually sharpen our insights, we feel that research attention to implementation of existing theory can make for real improvements in practice.

Finally, our research is a reminder of the old saying that too often in business we measure with a micrometer, mark with a pencil, and cut with an ax. Despite the many advances in finance theory, the particular "ax" available for estimating company capital costs remains a blunt one. Best-practice companies can expect to estimate their weighted-average cost of capital with an accuracy of no more than plus or minus 100 to 150 basis points. This has important implications for how managers use the cost of capital in decision making. First, do not mistake capital budgeting for bond pricing. Despite the tools available, effective capital appraisal continues to require thorough knowledge of the business and wise business judgment. Second, be careful not to throw out the baby with the bath water. Do not reject the cost of capital and attendant advances in financial management because your finance people are not able to give you a precise number. When in need, even a blunt ax is better than nothing.

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EXHIBIT 1
Three Survey Samples

Company Sample	Adviser Sample	Textbook/Trade Book Sample
Advanced Micro Devices	CS First Boston	Textbooks
Allergan	Dillon, Read	Brealey and Myers
Black & Decker	Donaldson, Lufkin, Jenrette	Brigham and Gapenski
Cellular One	J. P. Morgan	Gitman
Chevron	Lehman Brothers	Ross, Westerfield & Jaffe
Colgate-Palmolive	Merrill Lynch	Trade Books
Comdisco	Morgan Stanley	Copeland, Koller & Murrin
Compaq	Salomon	Ehrhardt
Eastman Kodak	Smith Barney	Ibbotson Associates
Gillette	Wasserstein Perella	
Guardian Industries		
Henkel		
Hewlett-Packard		
Kanthal		
Lawson Mardon		
McDonald's		
Merck		
Monsanto		
PepsiCo		
Quaker Oats		
Schering-Plough		
Tandem		
Union Carbide		
U.S. West		
Walt Disney		
Weyerhauser		
Whirlpool		

Note: For the full titles of textbooks and trade books, please see the preceding list of references.

EXHIBIT 2
General Survey Results

	Corporations	Financial Advisers	Textbooks/Trade Books
1. Do you use DCF techniques to evaluate investment opportunities?	89% Yes, as a primary tool 7% Yes, only as a secondary tool 4% No	100% rely on DCF, comparable companies multiples, comparable transactions multiples. Of these, 10% DCF is primary tool. 10% DCF is used mainly "as a check." 80% Weight the three approaches depending on purpose and type of analysis.	100% Yes
2. Do you use any form of a cost of capital as your discount rate in your DCF analysis?	89% Yes 7% Sometimes 4% N/A	100% Yes	100% Yes
3. For your cost of capital, do you form any combination of capital cost to determine a WACC?	85% Yes 4% Sometimes 4% No 7% N/A	100% Yes	100% Yes
4. What weighting factors do you use? *a.* target vs. current debt/equity? *b.* market vs. book weights?	*Target/Current*: 52% Target, 15% Current, 26% Uncertain, 7% N/A *Market/Book*: 59% Market, 15% Book, 19% Uncertain, 7% N/A	*Target/Current*: 90% Target, 10% Current *Market/Book*: 90% Market, 10% Book	*Target/Current*: 86% Target, 14% Current/Target *Market/Book*: 100% Market
5. How do you estimate your before tax cost of debt?	52% Marginal cost 37% Current average 4% Uncertain 7% N/A	60% Marginal cost 40% Current average	71% Marginal cost 29% No explicit recommendation
6. What tax rate do you use?	52% Marginal or statutory 37% Average historical 4% Uncertain 7% N/A	60% Marginal or statutory 30% Average historical 10% Uncertain	71% Marginal or statutory 29% No explicit recommendation
7. How do you estimate your cost of equity? (If you do not use CAPM, skip to question 12).	81% CAPM 4% Modified CAPM 15% N/A	80% CAPM 20% Other (including modified CAPM)	100% Primarily CAPM Other methods mentioned: dividend-growth model arbitrage pricing model
8. As usually written, the CAPM version of the cost of equity has three terms: a risk-free rate, a volatility or beta factor, and a market risk premium. Is this consistent with your company's approach?	85% Yes 0% No 15% N/A	90% Yes 10% N/A	100% Yes

EXHIBIT 2 *(continued)*

	Corporations	Financial Advisers	Textbooks/Trade Books
9. What do you use for the risk-free rate?	4% 90-day T-bill 7% 3–7 year Treasuries 33% 10-year Treasuries 4% 20-year Treasuries 33% 10–30 year Treasuries 4% 10 yrs. or 90-day; depends 15% N/A (Many said they match the term of the risk-free rate to the tenor of the investment)	10% 90-day T-bill 10% 5–10 year Treasuries 30% 10–30 year Treasuries 40% 30-year Treasuries 10% N/A	43% T-bills 29% LT Treasuries 14% Match tenor of investment 14% Don't say
10. What do you use as your volatility or beta factor?	52% Published source 3% Financial adviser's estimate 30% Self-calculated 15% N/A	30% Fundamental beta (e.g., BARRA) 40% Published source 20% Self-calculated 10% N/A	100% mention availability of published sources
11. What do you use as your market risk premium?	11% Use fixed rate of 4–4.5% 37% Use fixed rate of 5–6% 4% Use geometric mean 4% Use arithmetic mean 4% Use average of historical and implied 15% Use financial adviser's estimate 7% Use premium over Treasuries 3% Use Value Line estimate 15% N/A	10% Use fixed rate of 5% 50% Use 7–7.4% (Similar to arithmetic) 10% LT arithmetic mean 10% Both LT arithmetic and geometric mean 10% spread above Treasuries 10% N/A	71% Arithmetic historical mean 15% Geometric historical mean 14% Don't say
12. Having estimated your company's cost of capital, do you make any further adjustments to reflect the risk of individual investment opportunities?	26% Yes 33% Sometimes 41% No	Not asked	86% Adjust beta for investment risk 14% Don't say
13. How frequently do you reestimate your company's cost of capital?	4% Monthly 19% Quarterly 11% Semiannually 37% Annually 7% Continually/every investment 19% Infrequently 4% N/A (Generally, many said that in addition to scheduled reviews, they reestimate as needed for significant events such as acquisitions and high-impact economic events)	Not asked	100% No explicit recommendation
14. Is the cost of capital used for purposes other than project analysis in your	51% Yes 44% No 4% N/A	Not asked	100% No explicit discussion

EXHIBIT 2 *(concluded)*

	Corporations	Financial Advisers	Textbooks/Trade Books
company? (For example, to evaluate divisional performance?)			
15. Do you distinguish between strategic and operational investments? Is cost of capital used differently in these two categories?	48% Yes 48% No 4% N/A	Not asked	29% Yes 71% No explicit discussion
16. What methods do you use to estimate terminal value? Do you use the same discount rate for the terminal value as for the interim cash flows?	Not asked	30% Exit multiples only 70% Both multiples and perpetuity DCF model 70% Use same WACC for TV 20% No response 10% Rarely change	71% Perpetuity DCF model 29% No explicit discussion 100% No explicit discussion of separate WACC for terminal value
17. In valuing a multidivisional company, do you aggregate the values of the individual divisions, or just value the firm as a whole? If you value each division separately, do you use a different cost of capital for each one?	Not asked	100% Value the parts 100% Use different WACCs for separate valuations	100%: Use distinct WACC for each division
18. In your valuations do you use any different methods to value synergies or strategic opportunities (e.g., higher or lower discount rates, options valuation)?	Not asked	30% Yes 50% No 20% Rarely	29%: Use distinct WACC for synergies 71% No explicit discussion
19. Do you make any adjustments to the risk premium for changes in market conditions?	Not asked	20% Yes 70% No 10% N/A	14% Yes 86% No explicit discussion
20. How long have you been with the company? What is your job title?	Mean: 10 years All senior, except one	Mean: 7.3 years 4 MDs, 2 VPs, 4 associates	N/A

EXHIBIT 3
Betas for Corporate Survey Respondents

	Bloomberg Betas				
	Raw	Adjusted	Value Line Betas	S&P Betas	Range Maximum–Minimum
Advanced Micro	1.20	1.13	1.70	1.47	0.57
Allergan	0.94	0.96	1.30	1.36	0.42
Black & Decker	1.06	1.04	1.65	1.78	0.74
Cellular One			Not listed		
Chevron	0.70	0.80	0.70	0.68	0.12
Colgate-Palmolive	1.11	1.07	1.20	0.87	0.33
Comdisco	1.50	1.34	1.35	1.20	0.30
Compaq Computer	1.26	1.18	1.50	1.55	0.37
Eastman Kodak	0.54	0.69	NMF	0.37	0.32
Gillette	0.93	0.95	1.25	1.30	0.37
Guardian Industries			Not listed		
Henkel			Not listed		
Hewlett-Packard	1.34	1.22	1.40	1.96	0.74
Kanthal			Not listed		
Lawson Mardon			Not listed		
McDonald's	0.93	0.96	1.05	1.09	0.16
Merck	0.73	0.82	1.10	1.15	0.42
Monsanto	0.89	0.93	1.10	1.36	0.47
PepsiCo	1.12	1.08	1.10	1.19	0.11
Quaker Oats	1.38	1.26	0.90	0.67	0.71
Schering-Plough	0.51	0.67	1.00	0.82	0.49
Tandem Computers	1.35	1.23	1.75	1.59	0.52
Union Carbide	1.51	1.34	1.30	0.94	0.57
U.S. West	0.61	0.74	0.75	0.53	0.22
Walt Disney	1.42	1.28	1.15	1.22	0.27
Weyerhauser	0.78	0.85	1.20	1.21	0.43
Whirlpool	0.90	0.93	1.55	1.58	0.68
Mean	1.03	1.02	1.24	1.18	0.42
Median	1.00	1.00	1.20	1.21	0.42
Standard deviation	0.31	0.21	0.29	0.41	0.19

Note:

1. Bloomberg's adjusted beta is $\beta_{adj} = (.66)\beta_{raw} + (.33)1.00$

EXHIBIT 4
Variations in Cost-of-Capital (WACC) Estimates for Black & Decker Using Different Methods of Implementing the Capital Asset Pricing Model*

1. Short-term rate plus arithmetic average historical risk premium (recommended by some texts)
   R_f = 5.36%, 90-day T-bills
   $R_m - R_f$ = 8.50%, Ibbotson arithmetic average since 1926

Beta Service	Cost of Equity (K_e)	Cost of Capital (WACC)
Bloomberg, β = 1.06	14.40%	9.70%
Value Line, β = 1.65	19.40%	12.20%
S&P, β = 1.78	20.50%	12.80%

2. Long-term rate plus risk premium of 7.20% ("modal" practice of financial advisers surveyed)
   R_f = 6.26%, 30-year T-bonds
   $R_m - R_f$ = 7.20%, modal response of financial advisers

Beta Service	Cost of Equity (K_e)	Cost of Capital (WACC)
Bloomberg, β = 1.06	13.90%	9.40%
Value Line, β = 1.65	18.10%	11.60%
S&P, β = 1.78	19.10%	12.10%

3. Long-term rate plus risk premium of 5.50% ("modal" practice of corporations surveyed)
   R_f = 6.26%, 30-year T-bonds
   $R_m - R_f$ = 5.50%, modal response of corporations

Beta Service	Cost of Equity (K_e)	Cost of Capital (WACC)
Bloomberg, β = 1.06	12.10%	8.50%
Value Line, β = 1.65	15.30%	10.20%
S&P, β = 1.78	16.10%	10.50%

*In all cases the CAPM is used to estimate the cost of equity, the cost of debt is assumed to be 7.81 percent based on a Baa rating, the tax rate is assumed to be 38 percent, and debt is assumed to represent 49 percent of capital.

DOD-IR-87

[Ref. DOD-IR-47]

Please provide the requested information for HEI.

HECO Response:

The referenced DOD-IR-47 requested "the administrative costs and flotation cost components, including discounts, commissions, corporate expenses, offering spread, and market pressure as a percent of the market price for each of the following sources of equity: conversions of convertible preferred stock, dividend reinvestment plans, employee's savings plans, warrants and stock dividend programs." HEI does not have convertible preferred stock and warrants and stock dividend programs, and does not have information relating to the administrative costs and flotation cost components available from HEI's inception for its dividend reinvestment and employee's savings plans. Further, HECO objects to providing the requested information on the grounds that the research to attempt to compile this type of detailed information for the time period where there may be some information available would be unduly burdensome. (As stated in Dr. Morin's testimony HECO T-18, he does not rely on such information as it is impractical and prohibitively costly to start from the inception of a company and determine the source of all present equity and that a practical solution is to rely on the results of empirical studies which quantify the average flotation cost factor of a large sample of utility stock offerings.)

Without waiving HECO's objection, available non-public confidential financial information on the stock issuance costs for the dividend reinvestment and employee's savings plans is provided below pursuant to Amended Protective Order No. 23378. As of December 31, 2006, the total capital stock expenses, which includes costs related to the issuance of shares (e.g., legal expenses, printing costs and registrations fees), for the dividend reinvestment and employee's savings plans were [redacted] and [redacted] respectively.

DOD-IR-88

[Ref. DOD-IR-48]

a. For the "traditional" utility companies that have a Purchased Power percentage of 0%, does Value Line publish a 0% figure for those companies, or does Value Line not publish those data?

b. What is the publication date of the information provided?

c. Please explain why Avista and Cinergy were included in the group.

d. Please provide the percent Purchased Power for the T&D utilities.

e. What is "Hawaiian Energy Ind"?

<u>Dr. Morin's Response:</u>

a. Blank entries signify non-applicable. Zero entries mean zero.

b. The Value Line Survey was the most current information available as of May 18, 2007.

c. Avista missed the 50% utility revenue filter by only 1%, and Cinergy was recently acquired by Duke Energy and constitutes a large part of that company. Duke Energy is in the original sample from which the sample was derived.

d. Dr. Morin does not have that information for operating electric utility companies. One would reasonably think that stand-alone operating T&D-only utilities, with no power generation ownership, would purchase all of their power needs.

e. That should read Hawaiian Electric Industries, Inc.

DOD-IR-89

[Ref. DOD-IR-56]

If the example is the same (same flotation cost, same payout, same allowed return), but the market-to-book ratio is 1.1, is the resulting growth rate greater or less than the assumed 5%? Why?

Dr. Morin's Response:

That is an internally inconsistent hypothesis in the spreadsheet. The market-to-book ratio (M/B) is the output of the process and not the input. The stock price in the numerator of the M/B is given by the dividend divided by (k-g), and is in turn equal to earnings times the payout ratio. Earnings is the allowed return times the book equity. Thus, you cannot alter the M/B ratio, as it is the outcome of the process.

DOD-IR-90

[Ref. DOD-IR-58]

Please provide the information requested. Due to various office moves, the DOD cost of capital witness does not have access to data request responses provided in the Company's 2005 rate proceeding.

HECO Response:

Please see pages 2 to 5 for HECO's response to DOD/HECO-IR-3-39 in Docket No. 04-0113

(HECO's 2005 Test Year Rate Case) filed on April 13, 2005.

DOD/HECO-IR-3-39

[Gnechten Direct, p. 3, ll. 10-15]
Please list the capital structure, embedded cost rates and cost of equity requested by the Company in Docket Nos., 7766, 7700, and 6998.

HECO Response:

See the attached for the information from rebuttal testimonies in the referenced dockets.

Hawaiian Electric Company, Inc.

COMPOSITE EMBEDDED COST OF CAPITAL
Estimated 1995 Average

	(A)	(B)	(C)	(D)
	Capitalization			
	Amount in Thousands	Percent of Total	Earnings Requirements	Weighted Earnings Requirements (B) x (C)
Short-Term Debt	$47,328	5.46	5.00%	0.27%
Long-Term Debt	336,210	38.76	7.13%	2.76%
Preferred Stock	60,525	6.98	7.28%	0.51%
Common Equity	423,414	48.81	13.00%	6.35%
Total	$867,477	100.00		
Estimated Test Year Composite Cost of Capital				9.89%

NOTE: NUMBERS MAY NOT ADD EXACTLY DUE TO ROUNDING

Hawaiian Electric Company, Inc.

COMPOSITE EMBEDDED COST OF CAPITAL
Estimated 1994 Average

	(A)	(B)	(C)	(D)
	Capitalization			
	Amount in Thousands	Percent of Total	Earnings Requirements	Weighted Earnings Requirements (B) x (C)
Short-Term Debt	$45,240	5.56	4.00%	0.22%
Long-Term Debt	315,019	38.68	7.04%	2.72%
Preferred Stock	59,582	7.32	7.30%	0.53%
Common Equity	394,492	48.44	12.75%	6.18%
Total	$814,333	100.00		
Estimated Test Year Composite Cost of Capital				9.66%

NOTE: TOTALS MAY NOT ADD EXACTLY DUE TO ROUNDING

Hawaiian Electric Company, Inc.

COMPOSITE EMBEDDED COST OF CAPITAL
Estimated 1992 Average

	(A)	(B)	(C)	(D)
	Capitalization			
	Amount in Thousands	Percent of Total	Earnings Requirements	Weighted Earnings Requirements (B) x (C)
Short-Term Debt	$35,620	5.41	5.00%	0.27%
Long-Term Debt	250,352	38.04	7.79%	2.96%
Preferred Stock	61,396	9.33	7.41%	0.69%
Common Equity	310,823	47.22	13.50%	6.38%
Total	$658,191	100.00		
Estimated Test Year Composite Cost of Capital				10.30%

NOTE: TOTALS MAY NOT ADD EXACTLY DUE TO ROUNDING

DOD-IR-91

[Ref. DOD-IR-68]

Please provide any and all evidence (letters, memos, transcripts of telephone conversations, any form of correspondence, etc.) submitted by S&P to HECO indicating that S&P definitely intends to change HECO's risk factor from 30% to 50%.

HECO Response:

The Company does not have any further evidence submitted by S&P to HECO indicating that S&P definitely intends to change HECO's risk factor from 30% to 50%. However, based on S&P's May 7, 2007 publication, as presented in HECO's response to DOD-IR-68 of this proceeding and recent discussion with S&P, it is our understanding that all of HECO's firm capacity purchased power contracts would be assigned a 50% risk factor, since HECO's fixed capacity purchased power costs are recovered through base rates that are established in rate cases.

DOD-IR-92

[Ref. DOD-IR-70]

a) What proportion of the long-term debt currently on the books of HECO is represented by revenue bond debt?
b) Are the revenue bonds issued by the State of Hawaii, or the City and County of Honolulu and the Counties of Maui and Hawaii? Are those bonds rated by the rating agencies? If so, what are those ratings (provide a recent report); if not, please explain why not.
c) What proportion of the long-term debt currently on the books of HECO is represented by debt secured only by the revenue stream of HECO?
d) From what entity or firm does HECO purchase bond insurance? Please provide a complete copy of the most recent bond insurance agreement.
e) Would the bond rating of the revenue bonds be affected if HECO's bond rating were to change? If so, please explain how and why.

HECO Response:

a. HECO's long-term debt, as presented in HECO's financial statements, consists of long-term borrowings and hybrid securities. All of HECO's long-term borrowings are revenue bonds. Per HECO's financial statements as of March 31, 2007, revenue bonds are 94% of HECO's total long-term debt. It should be noted that the "Long-Term Debt" in HECO's Composite Cost of Capital for the Test Year 2007 Average presented in HECO-1901, consists of revenue bond issuances and other adjustments (see HECO-1903 for details). The "Hybrid Securities" are presented as a separate line item in HECO's Composite Cost of Capital in HECO-1901.

b. HECO's revenue bonds are issued by the Department of Budget and Finance of the State of Hawaii for the benefit of the utilities. All of the outstanding revenue bonds issued for HECO are insured and currently rated AAA by Standard & Poor's ("S&P") and Aaa by Moody's based upon a financial guarantee provided by the respective insurers. See attached pages 3 to 5 for the rating letters from S&P and Moody's for the most recent revenue bond sale for HECO.

c. All of HECO's total long-term debt (revenue bonds and hybrid securities) are unsecured. Payments are made under a pledge of the obligations of HECO to make the respective payments under the agreements, notes, and guarantees delivered pursuant to the agreements.

d. HECO's outstanding revenue bonds are currently insured by Financial Guaranty Insurance Company ("FGIC"), XL Capital Assurance Inc. ("XLCA"), Ambac Assurance Corporation ("AMBAC"), and Municipal Bond Investors Assurance Corporation ("MBIA"). A copy of the insurance agreement for the recent revenue bond Series 2007A and Refunding Series 2007B was filed with the Public Utilities Commission on May 25, 2007, as required by Decision & Order No. 23100 for Docket No. 2006-0383 (relating to the refunding bonds).

e. Yes, the bond rating of revenue bonds may be affected if HECO's credit rating were to change. Future revenue bonds, whether insured or not, may be affected as insurance premiums and/or the revenue bond interest rates are based upon HECO's credit ratings at the time of the sale. Further, although all of the outstanding revenue bonds issued for HECO are insured and the revenue bond rating for insured bonds are based upon a financial guarantee provided by the respective insurer, the rating of the outstanding revenue bonds are still subject to revision at any time.

It should also be noted that future annual insurance premiums for some of the outstanding revenue bonds may be affected if HECO's senior unsecured long-term debt rating and/or HECO's Issuer Rating were to change. Future annual insurance premiums for some of the existing insurance policies are based on the Company's senior unsecured long-term debt rating and/or the Company's Issuer Rating at the time the annual insurance premiums become due.

The McGraw-Hill Companies

STANDARD
&POOR'S

55 Water Street
New York, NY 10041

March 26, 2007

Mr. Jeffrey Fried
Financial Guaranty Insurance Co.
125 Park Avenue
New York, New York 10007

Re: **Department of Budget and Finance of the State of Hawaii - $140,000,00 - aggregate principal amount of the 4.65 % Special Purpose Revenue Bonds (Hawaiian Electric Company, Inc, and Subsidiaries Projects) Series 2007A - Policy # 07010122 - Dated March 27, 2007 due March 1, 2037**

Dear Mr. Fried:

Pursuant to your request for a Standard & Poor's rating on the subject obligations, we have reviewed the information submitted and have assigned a rating of "AAA".

This reflects our assessment of the likelihood of repayment of principal and interest based on the bond insurance policy your company is providing.

Rating adjustments may result from changes in the financial position of your company or from alterations in documents governing the issue. With respect to the latter, please notify us of any changes or amendments over the term of the issue.

When using the Standard & Poor's rating, include the definition of the rating together with a statement that this may be changed, suspended or withdrawn as a result of changes in, or unavailability of, information. This rating is not a "market rating", because it is not a recommendation to buy hold or sell the obligations.

If you have any questions, please feel free to contact me.

Very truly yours,

JS

The McGraw-Hill Companies

STANDARD
&POOR'S

55 Water Street
New York, NY 10041

March 27, 2007

Mr. Jeffrey Fried
Financial Guaranty Insurance Co.
125 Park Avenue
New York, New York 10007

Re: **Department of Budget and Finance of the State of Hawaii - $125,000,00 - aggregate principal amount of the 4.60 % Special Purpose Revenue Bonds (Hawaiian Electric Company, Inc, and Subsidiaries Projects) Refunding Series 2007B - Policy # 07010123 - Dated March 27, 2007 due May 1, 2026**

Dear Mr. Fried:

Pursuant to your request for a Standard & Poor's rating on the subject obligations, we have reviewed the information submitted and have assigned a rating of "AAA".

This reflects our assessment of the likelihood of repayment of principal and interest based on the bond insurance policy your company is providing.

Rating adjustments may result from changes in the financial position of your company or from alterations in documents governing the issue. With respect to the latter, please notify us of any changes or amendments over the term of the issue.

When using the Standard & Poor's rating, include the definition of the rating together with a statement that this may be changed, suspended or withdrawn as a result of changes in, or unavailability of, information. This rating is not a "market rating", because it is not a recommendation to buy hold or sell the obligations.

If you have any questions, please feel free to contact me.

Very truly yours,

JS

Moody's Investors Servic

100 Plaza 5
Harborside Financial Center
Jersey City, NJ 07311

March 27, 2007

Ms. Tayne S.Y. Sekimura
Financial Vice President and Chief Financial Officer
Hawaiian Electric Company, Inc.
900 Richards Street
P.O. Box 2750
Honolulu, Hawaii 96840

Dear Ms. Sekimura:

Per your request, Moody's Investors Service Rating Committee has reviewed a copy of the Official Statement of the Department of Budget and Finance of the State of Hawaii, dated March 20, 2007 relating to the $140,000,000 4.65% Special Purpose Revenue Bonds (Hawaiian Electric Company, Inc. and Subsidiaries Projects) Series 2007A due March 1, 2037 and the $125,000,000 4.60% Special Purpose Revenue Bonds (Hawaiian Electric Company, Inc. and Subsidiaries) Refunding Series 2007B due May 1, 2026.

Based upon our review and subject to final documentation, it is Moody's opinion that the Series 2007A bonds and the Refunding Series 2007B bonds, which both represent senior unsecured obligations of Hawaiian Electric Company, Inc., each be assigned an underlying rating of Baa1.

Also, effective today, Moody's Investors Service assigned a rating of Aaa (Financial Guaranty Insurance Company – Surety Bond Policy Number 07010122) to the $140,000,000 Series 2007A bonds and a rating of Aaa (Financial Guaranty Insurance Company – Surety Bond Policy Number 07010123) to the $125,000,000 Refunding Series 2007B bonds. The ratings are based upon a financial guarantee provided by Financial Guaranty Insurance Company for repayment of interest and principal.

Moody's rating is subject to revision or withdrawal at any time without prior notice. The rating and any revisions and withdrawals thereof are publicly disseminated by Moody's through normal print and electronic media and in response to oral requests to Moody's rating desk.

If I may be of further assistance, please call me at (901) 915-8756.

Sincerely,

AJ Sabatelle

Angelo J. Sabatelle
Vice President - Senior Credit Officer

DOD-IR-93

As a result of HECO's June 2007 updates, please show the net operating income, rate base and revenue requirement that HECO proposes.

a. Please identify and describe in detail all information not yet provided in the HECO June 2007 update and in the responses to previous CA and DOD IRs that HECO believes would be necessary in order to accurately determine the net operating income, rate base and revenue requirement that results after HECO's June 2007 updates.

b. Please provide all information identified in response to part a.

HECO Response:

HECO is providing a June 2007 update for HECO T-23 that includes the operating income, rate base, revenue requirement and other supporting documents resulting from the June 2007 Updates of the other witnesses and all revisions and supplements to those updates (which may be reflected in the Company's responses to information requests from the Consumer Advocate and the DOD).

a. The Company is identifying the changes to the June 2007 Updates in revisions and supplements to the updates which the Company is providing in separate filings.

b. See the response to a.

DOD-IR-94

Impact of HECO updates. Please confirm that HECO does not know and cannot quantify what its updated net operating income, rate base or revenue requirement is. If this is not the case, please show what HECO's updated net operating income, rate base or revenue requirement is in similar format to HECO's filing at the HECO-2301 and 2302 workpapers.

HECO Response:

See the Company's response to DOD-IR-93.

DOD-IR-95

HECO test year revenue and expense updates. Please confirm that HECO is proposing or has conceded to each of the updates shown in the following table and that the quantification of each is accurate. For any items listed where HECO has not conceded the adjustment, or for which HECO believes the adjustment is not accurately calculated, please explain fully, provide information that HECO believes is accurate, and reference each amount used in HECO's explanations to a source document and/or previously provided response to a CA or DOD information request:

Hawaiian Electric Company, Inc.
Adjusted Net Operating Income
(Thousands of Dollars)
Test Year Ending December 31, 2007

Line No.	Description	Per HECO Original Filing (A)	HECO June 2007 Updates (B)	HECO June 2007 Update References	HECO June 2007 Update Adjustment (C)
1	Electric Sales Revenue	$1,346,379	$ 1,348,635	T-3	$ 2,256
2	Other Operating Revenue	$ 3,391	$ 3,327	T-13, p.4	$ (64)
3	Gain on Sale of Land	$ 507	$ 500	T-13, p.4	$ (7)
4	TOTAL OPERATING REVENUES	$1,350,277	$ 1,352,462		$ 2,185
5	Fuel	$ 542,961	$ 543,874	T-4/CA-IR-214,p.7	$ 913
6	Purchased Power	$ 386,108	$ 386,872	T-5	$ 764
7	Production	$ 68,222	$ 68,925	T-6	$ 703
8	Transmission	$ 10,491	$ 10,378	T-7	$ (113)
9	Distribution	$ 24,722	$ 24,948	T-7	$ 226
10	Customer Accounts	$ 12,020	$ 11,929	T-8	$ (91)
11	Allowance for Uncollectibles	$ 1,358	$ 1,361	T-8	$ 3
12	Customer Service	$ 7,176	$ 7,270	T-9	$ 94
13	Administration and General	$ 72,007	$ 75,976	T-10	$ 3,969
14	Gen Excise Tax Rate Incr Adj	$ 320	**$ 320**	**Note A**	$ -
15	Operation and Maintenance	$1,125,385	$ 1,131,853		$ 6,468
16	Depreciation and Amortization	$ 79,736	$ 78,763	T-13	$ (973)
17	Amortization of State ITC	$ (1,321)	$ (1,304)	T-15	$ 17
18	Taxes Other Than Income	$ 126,151	**$ 126,151**	**Note B**	$ -
19	Interest on Customer Deposits	$ 375	$ 377	T-8	$ 2
20	Income Taxes	$ (4,107)	**$ (4,107)**	**Note C**	$ -
21	TOTAL OPERATING EXPENSES	$1,326,219	$ 1,331,733		$ 5,514
22	**NET OPERATING INCOME**	**$ 24,058**	**$ 20,729**		**$ (3,329)**
23	AVERAGE RATE BASE	$1,216,188	$ 1,176,461	T-17	$ 39,727
24	RATE OF RETURN ON RATE BASE	1.98%	1.76%		-0.22%

Notes and Source
Col.A: HECO-2302 "Present Rates" column
Col.B: DOD-114
Col.C: Col.B - Col.A

Notes:
[A] HECO-1508 not updated
[B] HECO-1501 not updated
[C] HECO-1502 not updated

HECO Response:

The numbers shown in column B (HECO June 2007 Updates) of the table above correctly reflect the Company's proposal at present rates with the following exceptions. The referenced materials clearly explain the reasons for the adjustments.

Line 2 – Other Operating Revenue

Correct Amount (000's) - $3,329

Reference: HECO T-8 June 2007 Update, page 8.

Comments: Other Operating Revenue also includes non-sales electric utility charges (at present rates) which total $2 (000's).

Line 7 – Production

Correct Amount (000's) – $70,077

Reference: CA-IR-232, CA-IR-344, CA-IR-488, DOD-IR-121

Line 14 – General Excise Tax Rate Incr Adj

Correct Amount (000's) - $328

Reference: DOD-IR-102

Line 18 – Taxes Other Than Income

Correct Amount (000's) - $126,284

Reference: Supplement to HECO T-15 June 2007 Update (to be filed)

Line 20 – Income Taxes

Correct Amount (000's) – ($6,634)

Reference: Supplement to HECO T-15 June 2007 Update (to be filed)

Line 23 – Average Rate Base/Line 24 – Rate of Return on Rate Base

See the Company's response to DOD-IR-96. Also, the amounts in column C for Lines 23 and 24 appear to have the wrong sign.

DOD-IR-96

Rate Base updated.

Please confirm that HECO is proposing or has conceded to each of the updates summarized in the following table and that the quantification of each update shown below is accurate. For any items listed below where HECO has not conceded the adjustment, or for which HECO believes the adjustment is not accurately calculated, please explain fully, provide information that HECO believes is accurate, and reference each amount used in HECO's explanations to a source document and/or previously provided response to a CA or DOD information request.

HECO Response:

Please see pages 2 and 3 for the current rate base schedule. The following items have been adjusted from the amounts presented in the June 2007 Update for HECO T-17, page 7 and are also reflected in the updated revenue requirement being provided in the June 2007 Update for HECO T-23.

a. Net Cost of Plant in Service has been updated and is shown on page 4. The balance has been updated due to adjustments to plant additions which will be described by Mr. Ken Morikami in the revised June 2007 (T-16) Update to be submitted shortly.

b. The Pension Asset and OPEB Amount have been updated as described by Ms. Patsy Nanbu in the June 2007 Update for HECO T-10.

c. Unamortized CIAC has been updated and is shown on page 5. The balance has been updated due to adjustments to cash and in-kind receipts which are described in the Company's response to CA-IR-395.

d. The Unamortized Net SFAS 109 Regulatory Asset, Accumulated Deferred Income Taxes and Unamortized ITC balances have been revised and will be described by Mr. Lon Okada in the revised June 2007 (T-15) Update to be submitted shortly.

e. Working cash has been revised and is shown in response to DOD-IR-97.

Hawaiian Electric Company, Inc.
2007 Average Rate Base
($ in thousands)

Investment in Assets Serving Customers	12/31/2006	12/31/2007	Average for 2007	HECO Reference	
Net Cost of Plant in Service	1,331,363	1,370,649	1,351,006	p. 4	
Property Held for Future Use	517	3,567	2,042	CA-IR-307	
Fuel Inventory	53,084	53,084	53,084	CA-IR-214	
Materials & Supplies Inventories	12,838	12,838	12,838	HECO-1703	
Unamortized Net SFAS 109 Regulatory Asset	49,429	51,405	50,417	T-15	**
Pension Asset	68,260	50,549	59,405	T-10	*
OPEB Amount	0	0	0	T-10	*
Unamortized System Development Costs	0	4,642	2,321	T-10	*
Unamortized DSG Regulatory Asset	0	0	0	T-17	*
ARO Regulatory Asset	27	26	27	T-17	*
Working Cash at Present Rates	26,271	26,271	26,271	DOD-IR-97	
Total Investments in Assets	1,541,789	1,573,031	1,557,410		
Funds from Non-Investors					
Unamortized CIAC	164,092	176,802	170,447	p. 5	
Customer Advances	1,001	756	879	CA-IR-307	
Customer Deposits	6,369	6,827	6,598	T-8	*
Accumulated Deferred Income Taxes	152,438	139,685	146,062	T-15	**
Unamortized ITC	28,523	30,065	29,294	T-15	**
Unamortized Gain on Sales	1,582	1,214	1,398	T-10	*
Total Deductions	354,005	355,349	354,677		
Average Rate Base at Present Rates			1,202,733		
Change in Working Cash			(1,521)	DOD-IR-97	
Average Rate Base at Proposed Rates			1,201,212		

NOTE: Totals may not add exactly due to rounding.

* Reference to June 2007 Update
** See revised June 2007 Update, HECO T-15

Hawaiian Electric Company, Inc.

2007 Average Rate Base (Current Effective Rates)

($ in thousands)

Investment in Assets Serving Customers	12/31/2006	12/31/2007	Average for 2007	HECO Reference	
Net Cost of Plant in Service	1,331,363	1,370,649	1,351,006	p. 4	
Property Held for Future Use	517	3,567	2,042	CA-IR-307	
Fuel Inventory	53,084	53,084	53,084	CA-IR-214	
Materials & Supplies Inventories	12,838	12,838	12,838	HECO-1703	
Unamortized Net SFAS 109 Regulatory Asset	49,429	51,405	50,417	T-15	**
Pension Asset	68,260	50,549	59,405	T-10	*
OPEB Amount	0	0	0	T-10	*
Unamortized System Development Costs	0	4,642	2,321	T-10	*
Unamortized DSG Regulatory Asset	0	0	0	T-17	*
ARO Regulatory Asset	27	26	27	T-17	*
Working Cash at Present Rates	25,718	25,718	25,718	DOD-IR-97	
Total Investments in Assets	1,541,236	1,572,478	1,556,857		
Funds from Non-Investors					
Unamortized CIAC	164,092	176,802	170,447	p. 5	
Customer Advances	1,001	756	879	CA-IR-307	
Customer Deposits	6,369	6,827	6,598	T-8	*
Accumulated Deferred Income Taxes	152,438	139,685	146,062	T-15	**
Unamortized ITC	28,523	30,065	29,294	T-15	**
Unamortized Gain on Sales	1,582	1,214	1,398	T-10	*
Total Deductions	354,005	355,349	354,677		
Average Rate Base at Present Rates			1,202,180		
Change in Working Cash			(968)	DOD-IR-97	
Average Rate Base at Proposed Rates			1,201,212		

NOTE: Totals may not add exactly due to rounding.

* Reference to June 2007 Update
** See revised June 2007 Update, HECO T-15

Hawaiian Electric Company, Inc.
Net Cost of Plant in Service
($ in thousands)

	Original Cost	Accum. Depreciation, Removal Reg. Liability, Acc. Retirement Oblig.	Net Plant In Service	HECO Reference
Recorded Balances - 12/31/06	2,453,556	(1,122,193)	1,331,363	
ESTIMATED CHANGES in 2007:				
Net Plant Additions	122,543		122,543	June 2007 Update T-16
Cost of Removal		5,764	5,764	June 2007 Update T-13
Salvage		(236)	(236)	June 2007 Update T-13
Depreciation Accrual		(88,785)	(88,785)	June 2007 Update T-13
Retirements [1]	(13,005)	13,005	0	June 2007 Update T-13
Estimated Balances - 12/31/07	2,563,094	(1,192,445)	1,370,649	
AVERAGE 2007 BALANCE			**1,351,006**	

NOTE: Totals may not add exactly due to rounding.

[1] Original cost of estimated retirements for the respective year.

Hawaiian Electric Company, Inc.

Unamortized Contributions In Aid of Construction

($ in thousands)

		HECO Reference
RECORDED BALANCE - 12/31/06	164,092	
ESTIMATED CHANGES in 2007:		
Cash Receipts	12,106	CA-IR-395
In-Kind Receipts	8,829	CA-IR-395
Transfer from Advances	264	CA-IR-307
Amortization	(8,489)	June 2007 Update T-13
ESTIMATED BALANCE - 12/31/07	176,802	
AVERAGE 2007 BALANCE	170,447	

NOTE: Totals may not add exactly due to rounding.

DOD-IR-97

Refer to the June 2007 update for T-17, page 12 of 18.

a. Note A states: "The working cash estimate will be updated upon the finalization of all the updates and the recalculation of the revenue requirement." When does HECO intend to provide such information?

b. What information does HECO not yet have that prevents the Company from updating the working cash calculation? For each item of information that prevents HECO from updating the working cash calculation, please explain in detail (1) why HECO does not have such information, (2) when HECO anticipates having such information, and (3) what HECO has not yet done but must still do in order to obtain such information.

c. What is the annual amount of fuel purchases after reflecting HECO's June 2007 update? List the amount and provide the source.

d. What is the annual amount of O&M labor after reflecting HECO's June 2007 update? List the amount and provide the source.

e. What is the annual amount of O&M nonlabor after reflecting HECO's June 2007 update? List the amount and provide the source.

f. What is the annual amount of purchased power after reflecting HECO's June 2007 update? List the amount and provide the source.

g. What is the annual amount of revenue taxes at present rates after reflecting HECO's June 2007 update? List the amount and provide the source.

h. What is the annual amount of income taxes at present rates after reflecting HECO's June 2007 update? List the amount and provide the source.

HECO Response:

a. Please see pages 2 and 3 for the updated Test Year working cash estimate.

b. Not applicable. See response to item a. above.

c. Please see pages 2 and 3.

d. Please see pages 2 and 3.

e. Please see pages 2 and 3.

f. Please see pages 2 and 3.

g. Please see pages 2 and 3.

h. Please see pages 2 and 3.

Hawaiian Electric Company, Inc.
WORKING CASH ITEMS, 2007
($ in thousands)

	(A) Revenue Collection Lag (Days)	Payment Lag Workpaper Reference	(B) Payment Lag (Days)	(C) Net Collection Lag (Days) (A) - (B)	Annual Amount Workpaper Reference	(D) Annual Amount	(E) Average Daily Amount - Present (D) / 365	(F) Working Cash Required (Provided) under Present Rates (C) x (E)	(G) Average Daily Amount - Proposed (D) / 365	(H) Working Cash Required (Provided) under Proposed Rates (C) x (G)
	per HECO T-8	HECO WP-1706								
ITEMS REQUIRING WORKING CASH:										
					JUNE 2007 UPDATE, HECO T-23					
Fuel Purchases	37	p. 1	17	20		537,767	1,473	29,467	1,473	29,467
O&M Labor	37	p. 8	11	26		89,202	244	6,354	244	6,354
O&M Nonlabor	37	JUNE 2007 UPDATE, p. 14.	32	5		118,932	326	1,629	326	1,629
Pension Asset Amortization	37	JUNE 2007 UPDATE, p. 16.	0	37		5,055	14	512	14	512
ITEMS PROVIDING WORKING CASH:										
Purchased Power	37	p. 37	39	(2)		386,872	1,060	(2,120)	1,060	(2,120)
Revenue Taxes - Present Rates	37	JUNE 2007 UPDATE, p. 17.	66	(29)		119,918	329	(9,528)		
Revenue Taxes - Proposed Rates	37	JUNE 2007 UPDATE, p. 17.	66	(29)		133,462			366	(10,604)
Income Taxes - Present Rates	37	p. 46	40	(3)		5,240	14	(43)		
Income Taxes - Proposed Rates	37	p. 46	40	(3)		59,374			163	(488)
Total WORKING CASH								26,272		24,751
Change in WORKING CASH										**(1,521)**

NOTE: Totals may not add exactly due to rounding.

Hawaiian Electric Company, Inc.

WORKING CASH ITEMS, 2007 (Current Effective Rates)

($ in thousands)

	(A) Revenue Collection Lag (Days)	Payment Lag Workpaper Reference	(B) Payment Lag (Days)	(C) Net Collection Lag (Days) (A) - (B)	Annual Amount Workpaper Reference	(D) Annual Amount	(E) Average Daily Amount - Effective (D) / 365	(F) Working Cash Required (Provided) under Effective Rates (C) x (E)	(G) Average Daily Amount - Proposed (D) / 365	(H) Working Cash Required (Provided) under Proposed Rates (C) x (G)
	per HECO T-8	HECO WP-1706								
ITEMS REQUIRING WORKING CASH:					JUNE 2007 UPDATE, HECO T-23					
Fuel Purchases	37	p. 1	17	20		537,767	1,473	29,467	1,473	29,467
O&M Labor	37	p. 8	11	26		89,202	244	6,354	244	6,354
O&M Nonlabor	37	JUNE 2007 UPDATE, p. 14.	32	5		118,932	326	1,629	326	1,629
Pension Asset Amortization	37	JUNE 2007 UPDATE, p. 16.	0	37		5,055	14	512	14	512
ITEMS PROVIDING WORKING CASH:										
Purchased Power	37	p. 37	39	(2)		386,872	1,060	(2,120)	1,060	(2,120)
Revenue Taxes - Effective Rates	37	JUNE 2007 UPDATE, p. 17.	66	(29)		124,843	342	(9,919)		
Revenue Taxes - Proposed Rates	37	JUNE 2007 UPDATE, p. 17.	66	(29)		133,461			366	(10,604)
Income Taxes - Effective Rates	37	p. 46	40	(3)		24,899	68	(205)		
Income Taxes - Proposed Rates	37	p. 46	40	(3)		59,374			163	(488)
Total WORKING CASH								25,719		24,751
Change in WORKING CASH										**(968)**

NOTE: Totals may not add exactly due to rounding.

DOD-IR-98

Refer to the June 2007 update for T-17, page 16 of 18, and to HECO T-10 June 2007 update.

a. Is the $5.055 million proposed amortization in addition to the pension expense determined under SFAS 87? If not, explain fully.

b. Is the $5.055 million proposed amortization in addition to the pension expense determined under SFAS 158? If not, explain fully.

c. Identify the generally accepted accounting principles that HECO relies upon for the pension amortization of $5.055 million. Within each GAAP relied upon by HECO, please identify the specific provisions which address pension amortization.

d. Has HECO ever included a pension asset amortization in any prior rate case? If so, please identify the case and provide the related testimony and exhibits. If not, explain fully why not.

<u>HECO Response:</u>

a. The $5.055 million proposed amortization in addition to the pension expense is consistent with the pension tracking mechanism proposed in HECO T-10 June 2007 Update. The proposed pension tracking mechanism mirrors the pension tracking mechanism approved by the Commission on an interim basis for HELCO in Docket No. 05-0315. The proposed amortization is not determined under SFAS No. 87 or under SFAS No. 158.

b. See response to subpart a.

c. Refer to SFAS No. 71, "Account for the Effects of Certain Types of Regulation." If a regulator includes costs in allowable costs in a period other than the period in which the costs would be charged to expense by an unregulated company in determining the regulated company's rates, the regulated company would account for such costs as determined by the regulator. If the proposed pension tracking mechanism, which proposes to amortize the pension asset and recover the amortized costs in rates, is approved by the Commission, the amortization of the pension asset would be considered generally accepted accounting principles, under SFAS No. 71.

d. HECO has not included a pension asset amortization in a prior rate case. However, as stated in response to subpart a, the Commission approved on an interim basis for HELCO in Docket No. 05-0315, a pension tracking mechanism, which included the amortization of the pension asset over five years, with the annual amortization included in expense in determining HELCO's revenue requirements.

DOD-IR-99

[Refer to HECO-1901]

Refer to HECO-1901. Was this schedule impacted in any way by HECO's June 2007 updates?

a. If so, please show in detail the revised composite embedded cost of capital for the test year 2007 average, in similar format to HECO-1901, reflecting all impacts from HECO's June 2007 updates.
b. If not, explain fully why not.

HECO Response:

a. No, HECO's composite cost of capital for the test year 2007 average, as shown in HECO-1901, was not impacted as a result of HECO's June 2007 updates.

b. There have been no significant changes to the cost of capital for the test year 2007, therefore, no revisions were made to HECO-1901. Please refer to the June 2007 Update for HECO T-19.

DOD-IR-100

Refer to HECO-1706 and HECO-1706(a)

a. Please identify all depreciation and amortization expenses included by HECO in its working cash calculation.

b. Has HECO excluded depreciation expense in its working cash calculation? If so, explain fully why depreciation expense was excluded.

c. Has HECO excluded amortization expense in its working cash calculation? If so, explain fully why amortization expense was excluded.

d. Is HECO aware of any prior Commission decisions which address how non-cash items such as depreciation and amortization expense are to be treated in the calculation of working cash? If so, please identify each such order.

e. In any of its most recent three rate cases, has HECO been allowed to include non-cash items such as depreciation and amortization expense in the calculation of working cash? If so, please provide the calculation of working cash in each such case, and specifically identify the amounts of depreciation and amortization expense that HECO included in its calculation of working cash in each case.

HECO Response:

a. Depreciation expenses are not included by HECO in its working cash calculation. As described by Ms. Gayle Ohashi (T-17) in the June 2007 Update, the pension asset amortization has been included in the working cash calculation as a result of the proposed implementation of the pension tracking mechanism. Other amortizations included in the working cash calculation are:

   1. Amortization of System Development Costs presented by Ms. Patsy Nanbu (T-10) in the June 2007 Update,

   2. Regulatory Commission Expense presented by Mr. Bruce Tamashiro (T-13) in the June 2007 Update,

   3. Amortization of the Waiau Water Well Deferred Costs presented by Mr. Dan Giovanni in HECO T-6,

4. Amortization of the Kahe Unit 7 Deferred Costs presented by Mr. Dan Giovanni in HECO T-6, and
5. Amortization of the SFAS No. 106 OPEB Regulatory Asset presented by Ms. Julie Price in HECO-1203.

These amortization items are O&M non-labor expenses and were included in the O&M non-labor weighted average payment lag day calculation in HECO-WP-1706. This is consistent with the calculation accepted by the Commission in Interim Decision and Order No. 22050 (dated September 27, 2005) in Docket No. 04-0113, HECO's test year 2005 rate case. HECO acknowledges, however, that it has not done an extensive search of O&M non-labor expenses for amortization items.

Attached on page 9, for information purposes, HECO presents a refined working cash lag day calculation to properly reflect the payment lag associated with each identified amortization item. As previously stated in the June 2007 Update and HECO T-17, the Company's position is that <u>all</u> revenues should be included in the revenue collection lag and <u>all</u> payments should be included in the payment lag in the calculation of working cash. These amortization items were not separately identified in calculating the O&M non-labor payment lag previously. The Company's refined calculation reflects these amortization items individually and determines the appropriate payment lag days for each item. This refined calculation results in a weighted average payment lag for O&M non-labor expense of 30 days. Each amortization item is discussed below.

1. <u>Amortization of System Development Costs</u> - As described by Ms. Patsy Nanbu in HECO T-10, the Commission approved the deferral of development costs related to the OMS project and its inclusion in rate base in Decision and Order No. 21899 (dated

June 20, 2005) in Docket No. 04-0131. The average 2007 balance of unamortized system development costs is included in rate base as shown in the June 2007 Update, HECO T-10, Attachment 5. Because the unamortized balance is included in rate base, in a refined payment lag day calculation, the Company would apply a zero day payment lag to the amortization expense.

2. Regulatory Commission Expense – Upon further review of the accounting for this item, HECO's position is that the unamortized regulatory commission expense regulatory asset should be included in rate base because the regulatory asset represents an investment funded by investors. If this regulatory asset were included in rate base, it would be appropriate to include the test year amortization expense in the working cash calculation with a zero day payment lag. However, the Company recognizes the timing of such a proposal and is sensitive to the procedural schedule in this docket. Therefore, the Company has not included this regulatory asset in rate base in this rate case. The Company reserves the right, however, to bring this issue before the Commission in the future. As shown on page 10, HECO has calculated a negative 731 day payment lag for this amortization expense assuming the regulatory asset is not in rate base. The payment lag days were calculated by determining the period over which the Regulatory Commission Expense Regulatory Asset would be amortized and determining the estimated period of time over which regulatory commission expense payments were made. An estimated average payment date and estimated average amortization date was calculated and the lag between these two dates was determined. As the unamortized balance of this regulatory asset is not being included in rate base, the negative payment lag and the calculated working cash captures the difference in timing of the payment

and recovery in rates which will allow investors the opportunity to earn a return on their investment. To summarize, the Company's position is that either: 1) the Unamortized Regulatory Commission Expense should be included in rate base and the Regulatory Commission Expense should have a zero payment lag or 2) the Unamortized Regulatory Commission Expense is not included in rate base and the Regulatory Commission Expense has a negative 731 day payment lag. However, in consideration of simplifying the issues and expediting this docket, the Company is not proposing that the Unamortized Regulatory Commission Expense be included in rate base in this proceeding, or that the Regulatory Commission Expense have a negative 731 day payment lag. Thus, HECO is proposing that the working cash associated with the Regulatory Commission Expense, as calculated in the June 2007 Update, be used in this rate proceeding.

3. Amortization of Waiau Water Well Costs – As described in response to CA-IR-147, the Commission in Decision & Order No. 13618 (dated October 31, 1994) in Docket No. 7277 ruled that the unamortized balance should not be included in rate base. However, the Commission allowed a carrying charge to be calculated on the unamortized balance. While the unamortized balance is not included in rate base, the Commission allowed investors the opportunity to earn a return on their investment via the carrying charge. As such, in a refined payment lag day calculation, HECO would apply a zero day payment lag to the amortization expense.

4. Amortization of Kahe Unit 7 Costs – As described in response to CA-IR-41, the Commission in Decision and Order No. 18872 (dated September 5, 2001) in Docket No. 95-0047 approved the recording of a regulatory asset for the balance of any

unamortized deferred costs related to this project. The amortization of this regulatory asset was adjusted through agreement with the Parties, which was documented in Exhibit V of the stipulated settlement letter, dated September 16, 2005 in HECO's test year 2005 rate case. As a result, the unamortized balance as of June 30, 2005 is being amortized through December 31, 2008. However, the Commission did not allow for inclusion of this regulatory asset in rate base or allow for a carrying charge. In a refined payment lag day calculation, the Company would apply a zero day payment lag because a zero day payment lag is consistent with the Commission decision that did not allow a return on investor funds for this item.

5. <u>Amortization of SFAS 106 OPEB Regulatory Asset</u> – The amortization of the SFAS 106 OPEB Regulatory Asset was previously included in "OPEB Expense" in the O&M non-labor weighted average payment lag day calculation in HECO-WP-1706. As discussed by Ms. Gayle Ohashi in HECO T-17, the OPEB expense was applied a zero day payment lag in the calculation of the weighted average payment lag days for O&M non-labor expense. This payment lag was revised due to the proposed implementation of the OPEB tracking mechanism as discussed in the June 2007 Update, HECO T-17.

The refined payment lag day calculation provided for information purposes on page 9 results in a payment lag day estimate of 30 days, two days shorter than what was presented in the June 2007 Update. As stated above, HECO acknowledges that it has not conducted an extensive search for all amortization items, therefore, for purposes of simplifying the issues in this proceeding, HECO proposes that the revenue requirements in this proceeding be based on payment lag of 32 days. The Company's position is that the June 2007 Update payment lag days represents a reasonable estimate of the O&M non-labor payment lag days;

however, the Company reserves the right to propose the payment lag day treatment of the amortization items discussed above in a future rate proceeding. The higher estimate of 32 days (from the June 2007 Update) proposed by the Company results in a lower working cash requirement and a lower test year rate base than if the 30 payment lag days (per page 9 of this response) had been used.

b. Yes, depreciation expenses are excluded by HECO from its working cash calculation. However, as stated in HECO T-17, page 19-20, the Company believes that all revenues should be included in the revenue collection lag and all payments should be included in the payment lag in the calculation of working cash. The Company has excluded depreciation expense, which has been excluded by the Commission in previous decisions in the determination of working cash. This was done to simplify the issues in order to expedite the regulatory process in this case.

c. As described in the response to part a. above, certain amortization expenses were included in the working cash calculation.

d. In Decision and Order No. 8570 (dated December 12, 1985) in Docket No. 5081, HECO's test year 1985 rate case, and in Decision and Order No. 10993 (dated March 6, 1991) in Docket No. 6432, HECO's test year 1990 rate case, the Commission addressed the exclusion of depreciation expense and deferred taxes in the calculation of working cash.

e. The three most recent rate cases are: Docket No. 04-0113, HECO's 2005 test year rate case, Docket No. 7766, HECO's 1995 test year rate case and Docket No. 7700, HECO's 1994 test year rate case. HECO excluded depreciation expenses from its working cash calculation in these three rate cases. The treatment of the amortization expenses, discussed in response to part (a) above, in each of the three most recent rate cases is discussed below.

1. Amortization of System Development Costs – There were no unamortized system development costs included in rate base in HECO's 2005 and 1994 test year rate case. Therefore, there is no amortization expense in either of these rate cases. Amortization of system development costs was included as an O&M non-labor expense in the working cash calculation for the HECO 1995 test year rate case only. Approximately $1,567,000 in amortization expense was included as an O&M non-labor expense in the working cash calculation.
2. Regulatory Commission Expense – Regulatory commission expense was included as an O&M non-labor expense in the working cash calculation in all three of the most recent rate cases. Included in HECO's 2005 test year rate case, HECO's 1995 test year rate case and HECO's 1994 test year rate case were $198,000, $284,000 and $479,000, in regulatory commission expenses, respectively.
3. Amortization of Waiau Water Well Costs – Amortization of the deferred Waiau Water Well costs was included as an O&M non-labor expense in the working cash calculation in all three of the most recent rate cases. The estimated amortization expenses included in HECO's 2005 test year rate case, HECO's 1995 test year rate case and HECO's 1994 test year rate case were approximately $302,244, $145,000 and $72,000, respectively.
4. Amortization of Kahe Unit 7 Costs – Amortization of the deferred Kahe Unit 7 project costs were included as an O&M non-labor expense in the working cash calculation for the HECO 2005 test year rate case only. $321,000 in amortization expense was included as an O&M non-labor expense in the working cash calculation. As noted above, the Commission's decision authorizing the amortization was not issued until

September 5, 2001, subsequent to HECO's 1995 and 1994 test year rate cases. Therefore, this amortization expense was not included in these two rate cases.

5. Amortization of SFAS 106 OPEB Regulatory Asset – Amortization of the SFAS 106 OPEB Regulatory Asset was included as an O&M non-labor expense in the working cash calculation for the HECO 2005 test year rate case and the HECO 1995 test year rate case. The Commission issued Decision and Order No. 13659 (dated November 29, 1994), in Docket No. 7233 and No. 7243 (Consolidated) allowing the establishment of this regulatory asset to be amortized over an 18-year period beginning January 1, 1995. Therefore, there was no amortization expense included in HECO's 1994 test year rate case. $1,302,000 and $2,751,000 in amortization expenses were included as an O&M non-labor expense in the working cash calculation in the HECO 2005 test year rate case and the HECO 1995 test year rate case, respectively.

FOR INFORMATION PURPOSES ONLY

Hawaiian Electric Company, Inc.
Working Cash Study
O&M Non-Labor Payment Lag

File: S:_Company\RegulatoryAffairs\HECO TY 2007 Rate Case\DOD IR Response\5th Sub - DOD-IR-93 to 102\DOD-IR-100\[DOD-IR-100.xls]Summary
Source: Per Supporting Worksheets

	Test Year Expense ($000's) Note A	% of Total	Total Payment Lag Days	Reference	Weighted Average
Pension Expense[1]	$12,929	11%	14	June 2007 Update HECO T-17, p.15.	2 days
OPEB Expense[2]	$4,636	4%	85	June 2007 Update HECO T-17, p.15.	3 days
System Devel. Costs Amortization[3]	$158	0%	0	June 2007 Update HECO T-17, p.15.	0 days
Regulatory Commission Expense[4]	$320	0%	-731	p. 10	-2 days
Waiau Water Well Amortization[5]	$296	0%	0	DOD-IR-100(a)(3)	0 days
Kahe Unit 7 Amortization[5]	$321	0%	0	DOD-IR-100(a)(4)	0 days
Emission Fees[5]	$691	1%	306	HECO-WP-1706, p. 33-36	2 days
EPRI Dues[6]	$1,608	1%	-7	HECO-WP-1706, p. 33-36	0 days
Other Non-Labor O&M[7]	$97,974	82%	30	HECO-WP-1706, p. 33-36	25 days
	$118,932	100%			
O&M Non-Labor Payment Lag					**30 days**

NOTE: Totals may not add exactly due to rounding.

Note A

[1] Pension expense estimate based on 2007 Pension Accrual of $17,710k (per June 2007 Update HECO T-12) x 73% (based on 2006 % of Employee Benefits charged to O&M expense).

[2] OPEB expense estimate based on 2007 OPEB expense of $6,350k (per June 2007 Update HECO T-12) x 73% (based on 2006 % of Employee Benefits charged to O&M expense). Includes $1,302k of SFAS 106 Reg. Asset amortization.

[3] June 2007 Update, HECO T-10, Attachment 5

[4] June 2007 Update, HECO T-13, page 6.

[5] HECO T-6 or June 2007 Update, HECO T-6.

[6] EPRI Dues per HECO-1304

[7] Other Non-Labor O&M = Total O&M Non-Labor expense of $118,932k, less other items noted above.

FOR INFORMATION PURPOSES ONLY

Hawaiian Electric Company, Inc.
Working Cash Study
Regulatory Commission Expense
File: S:_Company\RegulatoryAffairs\HECO TY 2007 Rate Case\DOD IR Response\5th Sub - DOD-IR-93 to 102\DOD-IR-100\[DOD-IR-100.xls]Summary
Source:

2007 Test Year

	PAYMENTS MADE				AMORTIZATION PERIOD				
	BEGIN	END	AVE PAYMENT PERIOD (DAYS)	AVG. PAYMENT DATE	START AMORT.	END AMORT.	AVE AMORT PERIOD (DAYS)	AVE. AMORT. DATE	PAYMENT LAG (DAYS)
1st	8/1/06	3/31/08	304.5	6/1/07	12/1/07	11/30/10	548.0	6/1/09	-731.0

Regulatory Commission Expense	**-731.0**

<u>Assumptions</u>
- Interim D&O - November 2007
- Amortization begins December 2007
- Costs incurred through December 2007, paid through 3/31/08.

DOD-IR-101

Please show in detail how HECO's June 2007 updates affect the amounts shown on HECO original exhibits HECO-1501 and HECO-1502.

a. At minimum, please provide the "at present rates" amounts for the impact of HECO's updates on HECO-1501 and HECO-1502.

b. What is the amount of FICA taxes after HECO's June 2007 updates?

c. What is the amount of federal unemployment taxes after HECO's June 2007 updates?

d. What is the amount of state unemployment taxes after HECO's June 2007 updates?

e. What is the amount of public service company taxes after HECO's June 2007 updates?

f. What is the amount of public utility fees after HECO's June 2007 updates?

g. What is the amount of franchise royalty taxes after HECO's June 2007 updates?

h. Please show in detail how the amounts identified in parts b through g are calculated.

<u>HECO Response:</u>

a. See pages 2 and 3 of this response.

b. $6,305,000. See pages 4 and 5 of this response.

c. $61,000. This amount has not changed from direct.

d. $0. See CA-IR-162.

e. At present rates, public service company taxes is $79,483,000. At proposed rates, public service company taxes is $88,468,000. See page 6 of this response.

f. At present rates, public utility fees is $6,753,000. At proposed rates, public utility fees is $7,516,000. See page 6 of this response.

g. At present rates, franchise royalty taxes is $33,682,000. At proposed rates, franchise royalty taxes is $37,478,000. See page 6 of this response.

h. See pages 4 - 6 of this response.

**HAWAIIAN ELECTRIC COMPANY, INC.
TAXES OTHER THAN INCOME TAXES
CHARGED TO OPERATIONS**

TEST YEAR 2007

($ Thousand)

		A At Present Rates	B Adjustment	C At Proposed Rates
PAYROLL TAXES				
1	F.I.C.A. Taxes	6,305		6,305
2	Federal Unemployment Taxes	61		61
3	State Unemployment Taxes	-		-
4	Total Payroll Taxes	6,366	-	6,366
REVENUE TAXES				
5	Public Service Company Taxes	79,483	8,985	88,468
6	Public Utility Fees	6,753	763	7,516
7	Franchise Royalty Taxes	33,682	3,796	37,478
8	Total Revenue Taxes	119,918	13,544	133,462
9	TOTAL TAXES OTHER THAN INCOME TAXES	126,284	13,544	139,828

HAWAIIAN ELECTRIC COMPANY, INC.
COMPUTATION OF INCOME TAX EXPENSE
TEST YEAR 2007
($ Thousand)

		A At Present Rates	B Adjustment	C At Proposed Rates	References
1	Total Operating Revenues	1,352,464	152,824	1,505,288	
	Operating Expenses:				
2	Fuel Oil and Purchased Power	930,746		930,746	
3	Other Operation & Maint Exp	202,077	153	202,230	
4	Depreciation & Amortization	78,763		78,763	
5	Amortization of State ITC	(1,304)		(1,304)	HECO-1504
6	Taxes Other Than Income Taxes	126,284	13,544	139,828	HECO-1501
7	Other Interest, Net	377		377	
8	Total Operating Expenses	1,336,943	13,697	1,350,640	
9	Operating Income Before Taxes	15,521	139,127	154,648	
	Tax Adjustments:				
10	Interest Expense	(30,597)		(30,597)	HECO-WP-1502
11	Meals & Entertainment	81		81	HECO-WP-1502
12	Total Tax Adjustments	(30,516)	-	(30,516)	
13	Taxable Income for Rate-Making	(14,995)	139,127	124,132	
14	Composite Effective Income Tax Rate	38.9097744%	38.9097744%	38.9097744%	
	Composite Income Tax Expense				
15	before Federal Only Adjustments	(5,835)	54,134	48,299	
	Federal Only Adjustments:				
16	Domestic Production Activities Deduction*	(2,216)		(2,216)	
17	Preferred Stock Dividend Deduction	(66)	-	(66)	CA-IR-467
18	Total Federal Only Adjustments	(2,282)	-	(2,282)	
19	Federal Income Tax Rate	35.00%	35.00%	35.00%	
20	Federal Tax Adjustment	(799)	-	(799)	
21	TOTAL INCOME TAX EXPENSE	(6,634)	54,134	47,500	

* DPAD is not applicable to present rates, however, it is shown here to facilitate the proper calculation of revenue requirements.

HAWAIIAN ELECTRIC COMPANY, INC.
PAYROLL TAXES CHARGED TO OPERATIONS
TEST YEAR 2007
($ Thousand)

	Summary of Payroll Taxes Charged to Operations	2007 Test Year
1	FICA	6,305
2	Federal Unemployment Taxes	61
3	State Unemployment Taxes	0
4	Total Payroll Taxes Charged to Operations	6,366

	Allocation of Payroll Taxes Based on Labor Dollars Charged	Test Year Payroll Taxes
5	Capital	1,123
6	Operations	6,366
7	Others	1,371
	Total Payroll Taxes	8,860

	Breakdown of Payroll Taxes	Total Payroll Taxes (HECO-WP-1501)	Calculated Percentages	Payroll Taxes Charged to Operations
8	FICA	9,026	98.38%	6,305
9	FUTA	88	0.96%	61
10	SUTA	61	0.66%	0
11	Total Payroll Taxes	9,175	100.0%	6,366

HAWAIIAN ELECTRIC COMPANY, INC.
FICA TAXES CHARGED TO OPERATIONS
TEST YEAR 2007
($ Thousand)

	Proposed Rates	Reference
FICA Taxes per direct	6,325	HECO-1501, page 2
Additional DSM employees	5	CA-IR-122
Additional Production O&M employees	12	CA-IR-110
Overtime decrease for Production O&M employees	(33)	CA-IR-232
Engineering Retention Program	10	CA-IR-69
Special Project VP retire	(14)	June 2007 update, T-13, page 9
Revised FICA taxes	6,305	

HAWAIIAN ELECTRIC COMPANY, INC.
SUPPORT FOR PUBLIC SERVICE COMPANY (PSC) TAX,
PUBLIC UTILITY COMMISSION (PUC) FEES AND FRANCHISE ROYALTY TAXES
TEST YEAR 2007
($ Thousand)

PSC Tax Calculation	At Present Rates	At Proposed Rates	References
Electric Sales Revenues	1,348,635	1,500,639	June 2007 Update HECO T-23
Other Operating Revenues	3,329	4,149	June 2007 Update HECO T-23
Less: Bad Debt Deduction	(1,361)	(1,514)	June 2007 Update HECO T-8 (filed 6/29/07)
PSC Tax Base	1,350,603	1,503,274	
PSC Tax Rate	5.885%	5.885%	HECO-WP-1501
PSC Taxes	79,483	88,468	

PUC Fee Calculation	At Present Rates	At Proposed Rates	References
Electric Sales Revenues	1,348,635	1,500,639	June 2007 Update HECO T-23
Other Operating Revenues	3,329	4,149	June 2007 Update HECO T-23
Less: Bad Debt Deduction	(1,361)	(1,514)	June 2007 Update HECO T-8 (filed 6/29/07)
PUC Fees Base	1,350,603	1,503,274	
PUC Fees Rate	0.5%	0.5%	HECO-WP-1501
PUC Fees	6,753	7,516	

Franchise Royalty Taxes	At Present Rates	At Proposed Rates	References
Electric Sales Revenue	1,348,635	1,500,639	June 2007 Update HECO T-23
Less: Bad Debt Deduction	(1,361)	(1,514)	June 2007 Update HECO T-8 (filed 6/29/07)
Franchise Royalty Tax Base	1,347,274	1,499,125	
Franchise Royalty Tax Rate	2.5%	2.5%	HECO-WP-1501
Franchise Royalty Taxes	33,682	37,478	
Total Revenue Taxes	119,918	133,462	

DOD-IR-102

Is the estimated increase in General Excise Tax (GET) on HECO-1508 impacted in any way by HECO's June 2007 updates? If so, please show the impact in similar format to HECO-1508. If not, explain fully why not.

HECO Response:

Yes, see page 2 of this response.

HAWAIIAN ELECTRIC CO., INC.
ESTIMATED INCREASE IN GENERAL EXCISE TAX (GET)
TEST YEAR 2007

Expense Element Description	($ in thousands)	Reference
Estimated Direct Non-Labor O&M (C) = (A) + (B)	63,989	HECO 1508, pg. 1 of 3
O&M Adjustments in June Update:		
Distributed Generation	(240)	June 2007 Update, HECO T-6, pg. 1
Environmental Services	(126)	CA-IR-344
Smart Signal	(202)	DOD-IR-121
Base DSM Cost	(165)	CA-IR-122, pg. 6, Lines 33, 46-50
OMS Maintenance	(77)	June 2007 Update, HECO T-7, pg. 1
Remote Billing and Printing Process	(100)	June 2007 Update, HECO T-8, pg. 2
Axis/Strategizer Implemenation Costs	(271)	CA-IR 135, pg. 1
Reduction in Consultant Fees	(50)	CA-IR-290, pg. 2
Rents	24	CA-IR-299, Attach. 11 and HECO-1305
Light Fixture Work on Ward Parking Facility	(38)	June 2007 Update, HECO T-13, pg. 3
Updated Non-Labor O&M (D)	62,744	
Increase in GET Rate due to Surcharge (E)	0.5%	
Increase Due to .5% surcharge (F) = (D) x (E)	314	
4.5% Tax on Surcharge (G) = (F) x 4.5%	14	
Estimated Total O&M Increase related to GET Surcharge (F) + (G)	328	

DOD-IR-103

[Refer to HECO-WP-1502]

Interest deduction. Refer to HECO-WP-1502.

a. Refer to HECO-WP-1502, page 2 of 5. After taking into account the impact of HECO's June 2007 update, what is the amount of (1) interest on long-term debt expense, (2) interest expense on short-term debt, (3) interest expense on hybrid securities, and (4) AFUDC on debt?
b. After HECO's June 2007 update, at what amount and at what interest rate (or cost rate) is long-term debt reflected in HECO's capital structure?
c. After HECO's June 2007 update, at what amount and at what interest rate (or cost rate) is short-term debt reflected in HECO's capital structure?
d. After HECO's June 2007 update, at what amount and at what interest rate (or cost rate) are hybrid securities reflected in HECO's capital structure?
e. What is HECO's proposed capital structure, cost rates for each component of such capital structure, and weighted cost of capital after HECO's June 2007 update? Show in detail.
f. How did HECO determine the 30.72% ratio of debt to total AFUDC expenditures on HECO-WP-1502, page 2 of 5?
g. Has HECO included any Construction Work in Progress (CWIP) in its proposed rate base? If so, please identify the amounts of CWIP that HECO has included. If different for HECO's original filing and for HECO's June 2007 update, please provide the respective amounts of CWIP for each.
h. Has HECO included any other amounts in rate base that accrue AFUDC? If so, please identify the amounts that HECO has included. If different for HECO's original filing and for HECO's June 2007 update, please provide the respective amounts of CWIP for each.

HECO Response:

a. The Company has not changed its estimate of the cost of capital for the test year 2007 since the HECO update did not result in any significant changes to the relevant underlying assumptions. No revisions were made to HECO-1901 (the 2007 test year average composite embedded cost of capital). Please refer to HECO-1901 for information on the cost and amount of long-term debt, short-term debt and hybrid securities in the capital structure. However, AFUDC debt was revised to $2,661,026 and submitted with the response to CA-IR-387.

b. See response to part a.

c. See response to part a.

d. See response to part a.

e. See response to part a.

f. See response to CA-IR-387.

g. HECO has not included any CWIP in its proposed rate base.

h. Prior to being deemed used or useful, certain assets (e.g. CWIP and system development costs) accrue AFUDC. Upon being deemed used or useful, the assets (including the accrued AFUDC) are included in rate base and AFUDC accrual ceases at that point.

DOD-IR-104

Interest deduction.

a. Is HECO familiar with the "interest synchronization" procedure?

b. Please describe fully and in detail HECO's understanding of the "interest synchronization" procedure.

c. Is HECO aware of whether any state utility regulatory commissions employ the "interest synchronization" procedure for determining the income tax expense allowance?

d. If the answer to part c is affirmative, please state fully HECO's understanding of how many state utility regulatory commissions employ the "interest synchronization" procedure for determining the income tax expense allowance.

e. Does HECO agree that the "interest synchronization" procedure properly synchronizes these aspects of the ratemaking formula: (1) rate base, (2) income tax expense allowance, and (3) weighted cost of debt, as used in the capital structure and reflected in the return on rate base? If not, explain fully why not.

<u>HECO Response:</u>

a. Yes.

b. Interest synchronization is a ratemaking methodology which imputes a hypothetical interest expense amount, typically based on the embedded cost of debt, in the calculation of income taxes for ratemaking purposes. This topic has been fully discussed by the Department of Defense and HECO in the record of prior HECO cases, including Docket Nos. 6531, 6998 and 04-0113. HECO generally agrees with the DOD as to the methodology of the interest synchronization calculation. However, HECO does not agree with the DOD on the desirability of this methodology for ratemaking purposes. The Commission has also rejected the DOD's proposal to use interest synchronization in Docket Nos. 6531 and 6998.

c. HECO has not surveyed other jurisdictions for their current method of calculating the interest deduction for ratemaking income tax calculation purposes.

d. Not applicable.

e. HECO does not agree that the interest synchronization procedure properly synchronizes all aspects of the ratemaking formula. As was decided by the Commission in D&O No. 11699 in Docket No. 6998 and D&O No. 11317 in Docket No. 6531, interest synchronization imputes interest based on various components that make up rate base. These components include both investor and noninvestor funds and it is difficult to match the funding of these components. In fact, interest synchronization imputes hypothetical interest on rate base funded by federal investment tax credits, which is interest-free. Although this methodology may appear to synchronize rate base with the cost of debt and capital structure for calculating income tax expense, the assumption that interest should be imputed on what is clearly interest-free funding is not proper. The interest synchronization methodology assumes an interest deduction that does not exist and will not be deductible to reduce income tax expense. On the other hand, HECO's methodology attempts to estimate, as accurately as possible, the Company's deductible interest for income tax purposes in the test year. By doing so, the income tax expense calculation more properly reflects the tax cost for the test year.

DOD-IR-105

Security services expense. Please refer to the response to CA-IR-339 and CA-IR-70.

a. Please explain fully the staffing shortfall that HECO's security contractor has been experiencing (referenced in the explanation for CA-IR-339c).

b. For how long has HECO's security contractor been experiencing staffing shortfalls? If exact information is not available, provide HECO's best estimates.

c. Please identify the security contractor's actual hours through June 30, 2007 for each station: (1) Honolulu Station, (2) Kahe Station, (3) Waiau Station.

d. Refer to CA-IR-339, attachment 2. Has any cost for the camera repairs budgeted for the Kahe Station been incurred through June 30, 2007? If so, please identify the dates and amounts. If not, when does HECO expect such repairs to be completed and at what total cost?

e. Refer to CA-IR-339, attachment 2. Has any cost for the camera repairs and alarm monitoring budgeted for the Waiau Station been incurred through June 30, 2007? If so, please identify the dates and amounts. If not, when does HECO expect such repairs to be completed and at what total cost?

f. What specifically is involved in the "alarm monitoring" for Waiau Station? Do the security contractor provided personnel perform the "alarm monitoring"? If not, who performs it? Why is there an extra cost for it?

g. Why don't the other plants have a cost for "alarm monitoring"?

HECO Response:

a. As was stated in the response to CA-IR-486: HECO's security contractor has been experiencing a staffing shortfall due to difficulties in hiring and retaining employees. While the hiring and retention of the contractor personnel is not a HECO responsibility, HECO's contractor has expressed that the difficulties are due to, 1) the low unemployment rate in Hawaii constraining the pool of potential hires, 2) the competitive wage rates being offered by other security companies, and 3) other contracts within the contractor organization offering higher pay. Because of the staffing shortfall, HECO's security contractor has not been able to provide the security officers and hours, stipulated in the contract.

b. HECO's security contractor has been experiencing staffing shortfall difficulties since the fourth quarter of 2006.

c. Please refer to Attachment 1 to the response to CA-IR-486, HECO's security contractor's actual hours through June 30, 2007 for each station: (1) Honolulu Station, (2) Kahe Station, (3) Waiau Station.

d. No, there have been no costs incurred as of June 30, 2007, for the Kahe camera repairs. Two invoices totaling $2,683.77 were received in July 2007 and are being processed for payment for the Kahe camera repairs (Attachment 1 to this response is a copy of the invoice received). Additional invoices are expected based on work provided by the security vendor and it is projected that the amount budgeted of $6,600 will be spent.

e. Cost has not been incurred as of June 30, 2007 for the Waiau camera repairs. Four invoices totaling $3,373.35 have been received in July 2007 and are being processed for payment. Please refer to Attachment 2 to this response for copies of the invoices.

There are other cameras at Waiau needing repair and awaiting inspection by the repair contractor. Because the current repair contractor has unavailable, HECO is working to retain another vendor to assist with the backlog of repair work. At this point in time it is not possible to accurately estimate the additional cost for camera repairs, however, it is reasonable to assume that the amount budgeted of $8,000 will be expended in 2007.

Also shown on Attachment 2 to the response to CA-IR-339 is $15,300 for "Alarm Monitoring" at Waiau Station. Please see the response to subpart f, below, for a discussion of this item.

f. The cost shown in Attachment 2 to the response to CA-IR-339 for "Alarm Monitoring" at Waiau Station is $15,300. This cost is for security alarms and related services at HECO's Iwilei Tank Yard and selected electric substations. The major cost component of this total is for a telephone service link between the Iwilei Tank Yard and the HECO Security Office. Security personnel perform the surveillance, but the costs are for the data links, telephone links, and alarm service that are parts of the remote monitoring system.

g. Kahe Station and Honolulu Station do not have a cost for "Alarm Monitoring" because there is no remote monitoring system or alarm links tied to security service provided at these locations.

Tελos

	Service Invoice #	TC00723	Date of Srv Inv 7/5/2007

The Telos Corporation 1014 Kinau Street Honolulu, HI 96814 (808) 545-3110; (808) 356-0802 (Fax)

Customer PO #		Authorized By	Alan Cardoza
Customer Name	Hawaiian Electric Company	Contact Phone #'s	(808) 864-0565
Mailing Address	PO Box 2750	Location of Service	Kahe Power plant
	Honolulu, HI 96840-0001	Device(s) Serviced	Cameras
Telos Rep:	Teren Watumull	Rep Phone #'s	(808) 988-1915; (808) 772-8841

Service Request: Trouble Shoot/Repair Dome Cameras

Actual Problem(s)

Service Performed Replaced Dome Camera, Restarted 2nd Camera

Materials Used

Qnty	Unit	Description	Model/Part #	Cost	Extension
1	ea	Dome		$ 2,203.00	$ 2,203.00
					$ -
					$ -

Service Summary

Qnty	Unit	Description	Date of Service	Rate	Extension
3	Hours	Trouble Shoot Repair	6/22/2007	$ 90.00	$ 270.00
					$ -
					$ -
					$ -

Notes:

NHSR Normal hours service rate--$90
AHSR After hour service rate--$120
ESR Emergency service rate--$160

Material Sub-Total	**$ 2,203.00**
Shipping/Handling	
Labor Sub-Total	**$ 270.00**
Contract Sub-Total	**$ 2,473.00**
Tax 4.712	**$ 116.53**
Invoice Total	**$ 2,589.53**

Tελos

Service Invoice #	TC00715
Date of Srv Inv	7/11/2007

The Telos Corporation 1014 Kinau Street Honolulu, HI 96814 (808) 545-3110; (808) 356-0802 (Fax)

Customer PO #		Authorized By	Alan Cardoza
Customer Name	Hawaiian Electric Company	Contact Phone #'s	(808) 864-0565
Mailing Address	PO Box 2750	Location of Service	Kahe Power Plant
	Honolulu, HI 96840-0001	Device(s) Serviced	Door
Telos Rep:	Teren Watumull	Rep Phone #'s	(808) 988-1915; (808) 772-8841

Service Request: Trouble Shoot/Repair door Closure Problem

Actual Problem(s) Mechanical problem with door closure mechanism & AC pressure

Service Performed Inspected & advised replacement of closure mechanism & Adjustment of AC system

Materials Used

Qnty	Unit	Description	Model/Part #	Cost	Extension
					$ -
					$ -
					$ -

Service Summary

Qnty	Unit	Description	Date of Service	Rate	Extension
1.0	NHSR	Repositioned Camera	5/12/2007	$ 90.00	$ 90.00
					$ -
					$ -
					$ -

Notes:

NHSR Normal hours service rate--$90
AHSR After hour service rate--$120
ESR Emergency service rate--$160

Material Sub-Total	$ -
Shipping/Handling	
Labor Sub-Total	$ **90.00**
Contract Sub-Total	$ **90.00**
Tax 4.712	$ **4.24**
Invoice Total	$ **94.24**

Tελos

Service Invoice # TC00722

Date of Srv Inv 7/5/2007

The Telos Corporation **1014 Kinau Street** **Honolulu, HI 96814** **(808) 543-3110; (808) 356-0802 (Fax)**

Customer PO #		Authorized By	Alan Cardoza
Customer Name	Hawaiian Electric Company	Contact Phone #'s	(808) 864-0565
Mailing Address	PO Box 2750	Location of Service	Waiau Power Plant
	Honolulu, HI 96840-0001	Device(s) Serviced	HID Reader
Telos Rep:	Teren Watumull	Rep Phone #'s	(808) 988-1915; (808) 772-8841

Service Request: Repair Loose Reader

Actual Problem(s) Same

Service Performed Re-attached Loose Reader

Materials Used

Qnty	Unit	Description	Model/Part #		Cost		Extension
2	ea	Toggle bolts		$	1.00	$	2.00
						$	-
						$	-

Service Summary

Qnty	Unit	Description	Date of Service		Rate		Extension
1.5	Hours	Re-attach reader	6/21/2007	$	90.00	$	135.00
						$	-
						$	-
						$	-

Notes:

NHSR Normal hours service rate--$90
AHSR After hour service rate--$120
ESR Emergency service rate--$160

Material Sub-Total	$	2.00
Shipping/Handling		
Labor Sub-Total	$	135.00
Contract Sub-Total	$	137.00
Tax 4.712	$	6.46
Invoice Total	$	143.46

Tελos

Service Invoice # TC00711

Date of Srv Inv 7/10/2007

The Telos Corporation 1014 Kinau Street Honolulu, HI 96814 (808) 545-3110; (808) 356-0802 (Fax)

Customer PO #		Authorized By	Alan Cardoza
Customer Name	Hawaiian Electric Company	Contact Phone #'s	(808) 864-0565
Mailing Address	PO Box 2750	Location of Service	Waiau Power Plant
	Honolulu, HI 96840-0001	Device(s) Serviced	Aiphone System
Telos Rep:	Teren Watumull	Rep Phone #'s	(808) 988-1915; (808) 772-8841

Service Request: Trouble Shoot/Repair Aiphone

Actual Problem(s) No Plug in Transformer

Service Performed Installed new Plug in Transformer

Materials Used

Qnty	Unit	Description	Model/Part #	Cost	Extension
1	ea	Aiphone Power Supply		$ 11.54	$ 11.54
					$ -
					$ -

Service Summary

Qnty	Unit	Description	Date of Service	Rate	Extension
2.0	NHSR	Trouble Shoot/Repair/Clean	3/6/2007	$ 90.00	$ 180.00
					$ -
					$ -
					$ -

Notes:

NHSR Normal hours service rate--$90
AHSR After hour service rate--$120
ESR Emergency service rate--$160

Material Sub-Total	$ **11.54**
Shipping/Handling	
Labor Sub-Total	$ **180.00**
Contract Sub-Total	$ **191.54**
Tax 4.712	$ **9.03**
Invoice Total	$ **200.57**

Tελos

Service Invoice # TC00713

Date of Srv Inv 7/10/2007

The Telos Corporation **1014 Kinau Street** **Honolulu, HI 96814** **(808) 545-3110; (808) 356-0802 (Fax)**

Customer PO #		Authorized By	Alan Cardoza
Customer Name	Hawaiian Electric Company	Contact Phone #'s	(808) 864-0565
Mailing Address	PO Box 2750	Location of Service	Waiau Power Plant
	Honolulu, HI 96840-0001	Device(s) Serviced	Dome Cameras
Telos Rep:	Teren Watumull	Rep Phone #'s	(808) 988-1915; (808) 772-8841

Service Request: Trouble Shoot/Repair/Clean Dome Cameras

Actual Problem(s)

Service Performed Replaced Dome Camera, Repaired/Cleaned additional cameras

Materials Used

Qnty	Unit	Description	Model/Part #	Cost	Extension
1	ea	Day Night Ultra VII Dome Camera	RAS917	$ 2,203.00	$ 2,203.00
					$ -
					$ -

Service Summary

Qnty	Unit	Description	Date of Service	Rate	Extension
4.0	NHSR	Trouble Shoot/Repair/Clean	3/9/2007	$ 90.00	$ 360.00
4.0	Hrs	Bucket Truck	3/9/2007	$ 60.00	$ 240.00
					$ -
					$ -

Notes:

NHSR Normal hours service rate--$90

AHSR After hour service rate--$120

ESR Emergency service rate--$160

Material Sub-Total	**$ 2,203.00**
Shipping/Handling	
Labor Sub-Total	**$ 600.00**
Contract Sub-Total	**$ 2,803.00**
Tax 4.712	**$ 132.08**
Invoice Total	**$ 2,935.08**

Telos

Service Invoice # TC00716

Date of Srv Inv 7/11/2007

The Telos Corporation 1014 Kinau Street Honolulu, HI 96814 (808) 545-3110; (808) 356-0802 (Fax)

Customer PO #		Authorized By	Alan Cardoza
Customer Name	Hawaiian Electric Company	Contact Phone #'s	(808) 864-0565
Mailing Address	PO Box 2750	Location of Service	Waiau Pwr Plant Admin Bldg
	Honolulu, HI 96840-0001	Device(s) Serviced	Camera in Ceiling Housing
Telos Rep:	Teren Watumull	Rep Phone #'s	(808) 988-1915; (808) 772-8841

Service Request: Reposition Camera in Admin Bldg Waiau

Actual Problem(s)

Service Performed Repositioned camera

Materials Used

Qnty	Unit	Description	Model/Part #	Cost	Extension
					$ -
					$ -
					$ -

Service Summary

Qnty	Unit	Description	Date of Service	Rate	Extension
1.0	NHSR	Repositioned Camera	4/22/2007	$ 90.00	$ 90.00
					$ -
					$ -
					$ -

Notes:

NHSR Normal hours service rate--$90

AHSR After hour service rate--$120

ESR Emergency service rate--$160

Material Sub-Total	$ -
Shipping/Handling	
Labor Sub-Total	$ 90.00
Contract Sub-Total	$ 90.00
Tax 4.712	$ 4.24
Invoice Total	$ 94.24

DOD-IR-106

Dividend deduction. Refer to CA-IR-385 and CA-IR-467

a. As a result of the dividend deduction, should state and federal income tax expenses be reduced by 38.907744% x $66,463 = $25,859?

b. If not, what is the reduction to income tax expense related to reflecting the dividend deduction and how is it calculated?

HECO Response:

a. No.

b. The dividend deduction is only recognized for federal income taxes. This special deduction under §247 of the Internal Revenue Code was not adopted by the Hawaii income tax law. Therefore, the reduction to income tax expense should be at the federal rate only, or 35% x $66,463 = $23,262.

DOD-IR-107

Refer to the June 2007 update for HECO T-10, Attachments 8, 9 and 10. Also refer to HECO-1021, page 2 of 2.

a. If a pension tracking mechanism, similar to the one that HECO is currently proposing, would have been in effect in 1995, what would the deferrals and rate impacts have been through 2007? Show in detail by year. If exact amounts are not available, provide HECO's best estimates and show in detail how such estimates were derived.

b. If an OPEB tracking mechanism, similar to the one that HECO is currently proposing, would have been in effect in 1995, what would the deferrals and rate impacts have been through 2007? Show in detail by year. If exact amounts are not available, provide HECO's best estimates and show in detail how such estimates were derived.

c. If an OPEB tracking mechanism, similar to the one that HECO is currently proposing, would have been in effect in the first year in which HECO was allowed to use the FAS 106 accrual method for determining OPEB costs for ratemaking purposes, what would the deferrals and rate impacts have been? Show in detail by year. If exact amounts are not available, provide HECO's best estimates and show in detail how such estimates were derived.

d. Refer to the June 2007 update for HECO T-10, Attachment 10 and to HECO-1021, page 2 of 2. Explain fully why contributions to the pension trust prior to 1995 are relevant to setting rates prospectively based on a 2007 test year adjusted for known and measurable changes.

e. Refer to the June 2007 update for HECO T-10, Attachment 10. In each year from 1999 through 2007 in which HECO shows a zero amount as the "Contributions to Trust" identify what the maximum tax-deductible contribution was for each such year. Include supporting documentation.

f. Refer to the June 2007 update for HECO T-10, Attachment 10. (1) Please identify each rate case HECO had since 1986; (2) identify the test year used for each such rate case; (3) identify the amount of NPPC accrual recorded in each rate case test year; (4) identify the amount of pension expense in each test year that HECO had requested be reflecting in determining its revenue requirement; and (5) identify the amount of pension expense in each test year that was reflected in the revenue requirement approved by the Commission in each case. If exact amounts are not known, please provide HECO's best estimates and show in detail how such estimates were derived.

g. Please provide a copy of any and all source documents used or relied upon by HECO to provide the information in part f.

HECO Response:

a. See page 3 of this response.

b. See page 4 of this response.

c. The Commission allowed the Company to adopt SFAS 106 effective January 1, 1995. Therefore, the 1995 test year was the first year in which HECO was allowed to use the FAS 106 accrual method for determining OPEB costs for ratemaking purposes. See page 4 of this response.

d. Contributions to the trust fund and the net periodic pension cost since the inception of SFAS 87 were provided. The amounts prior to 1995 are for information purposes only. Because the cumulative contributions to the trust fund and the cumulative net periodic pension costs net to zero in the period prior to 1996, the amounts do not impact the 2007 test year.

e. The maximum tax deductible contributions for 1999-2007 were as follows:

1999	$0
2000	$0
2001	$0
2002	$0
2003	$23,080,742
2004	$67,377,607
2005	$76,324,682
2006	$37,035,984
2007	$75,356,124

These amounts were provided by the Company's actuary, Watson Wyatt.

f. See the response to CA-IR-158.

g. Specific citations to prior Commission decisions and orders and filings on public record were provided in the response to CA-IR-158.

DOD-IR-107
DOCKET NO. 2006-0386
PAGE 3 OF 5

Hawaiian Electric Company, Inc.
"What If" calculation for response to DOD-IR-107(a)

Test Year? (A)	Year (B)	Actual NPPC (C)	Actual Contributions to Pension Fund (D)	Cumulative Contributions to Pension Fund (E)	Change in Pension Amount (F)	Cumulative Pension Amount (G)	Difference Between Pension Cost in Rates and Actual NPPC (H)	Cumulative Regulatory Asset (Liability) (I)	Difference Between Contributions to Fund and Pension Cost in Rates (J)	Cumulative Regulatory Asset (Liability) in Rate Base (K)	Total Pension Cost Deemed Recovered in Rates (L)	Cumulative Total Pension Cost in Rates (M)	Latest Test Year NPPC (N)	Amortization of Cumulative Pension Liability (O)	Transfers to Plant Based on NPPC in Rates (P)	Pension Exp after Transfers to Plant (Q)	Depreciation on Transfers to Plant (R)	Net Expense (S)	Pension Amount in Rate Base (T)	Accumulated Deferred Taxes Relating to Pension in RB (U)	Accumulated Transfers to Plant (V)	Accumulated Depreciation Related to Accumulated Transfers to Plant (W)	Ending Rate Base (X)	Test Year Revenue Requirement (Y)
Y	1995	6,408	9,058	-	-	-	-	-	-	-	9,058	9,058	9,499	-	3,194	6,305	106	6,411	-	-	3,194	(106)	3,088	7,257
	1996	8,381	6,972	6,972	(1,409)	(1,409)	(1,118)	(1,118)	(2,527)	(2,527)	9,499	18,557	9,499	-	2,850	6,649	201	6,851	(2,527)	983	6,044	(308)	4,192	N/A
	1997	7,117	5,876	12,848	(1,241)	(2,650)	(2,382)	(3,500)	(3,623)	(6,150)	9,499	28,056	9,499	-	2,850	6,649	296	6,946	(6,150)	2,393	8,893	(604)	4,532	N/A
	1998	1,871	2,206	15,054	335	(2,315)	(7,628)	(11,128)	(7,293)	(13,443)	9,499	37,555	9,499	-	2,850	6,649	391	7,041	(13,443)	5,231	11,743	(996)	2,535	N/A
	1999	(1,074)	-	15,054	1,074	(1,241)	(10,573)	(21,701)	(9,499)	(22,942)	9,499	47,054	9,499	-	2,850	6,649	486	7,136	(22,942)	8,927	14,593	(1,482)	(905)	N/A
	2000	(19,322)	-	15,054	19,322	18,081	(28,821)	(50,522)	(9,499)	(32,441)	9,499	56,553	9,499	-	2,850	6,649	581	7,231	(32,441)	12,623	17,443	(2,064)	(4,439)	N/A
	2001	(20,465)	-	15,054	20,465	38,546	(29,964)	(80,486)	(9,499)	(41,940)	9,499	66,052	9,499	-	2,850	6,649	676	7,326	(41,940)	16,319	20,292	(2,740)	(8,069)	N/A
	2002	(15,656)	-	15,054	15,656	54,202	(25,155)	(105,641)	(9,499)	(51,439)	9,499	75,551	9,499	-	2,850	6,649	771	7,421	(51,439)	20,015	23,142	(3,511)	(11,794)	N/A
	2003	5,894	13,394	28,448	7,500	61,702	(3,605)	(109,246)	3,895	(47,544)	9,499	85,050	9,499	-	2,850	6,649	866	7,516	(47,544)	18,499	25,992	(4,378)	(7,431)	N/A
	2004	(1,547)	15,186	43,634	16,733	78,435	(11,046)	(120,292)	5,687	(41,857)	9,499	94,549	9,499	-	2,850	6,649	961	7,611	(41,857)	16,286	28,841	(5,339)	(2,068)	N/A
Y	2005	4,588	6,000	49,634	1,412	79,847	(4,911)	(125,203)	(3,499)	(45,356)	9,499	104,048	-	(9,071)	-	(9,071)	961	(8,110)	(45,356)	17,648	28,841	(6,301)	(5,167)	(9,409)
	2006	14,237	-	49,634	(14,237)	65,610	23,308	(101,895)	9,071	(36,285)	(9,071)	94,977	-	(9,071)	-	(9,071)	961	(8,110)	(36,285)	14,118	28,841	(7,262)	(587)	N/A
Y	2007	17,711	-	49,634	(17,711)	47,899	26,782	(75,113)	9,071	(27,214)	(9,071)	85,906	-	(5,443)	-	(5,443)	961	(4,481)	(27,214)	10,589	28,841	(8,223)	3,993	(4,677)
		8,143	58,692								85,906													

(A) "Y" if Test Year
(B) Calendar Year
(C) Actual NPPC
(D) Actual Contributions to Pension Fund
(E) Cumulative Contributions to Pension Fund = prior (E) + (D)
(F) Change in Pension Amount = (D) - (C)
(G) Cumulative Pension Amount = prior (G) + (F)
(H) Difference Between Pension Cost in Rates and Actual NPPC = (C) - (L)
(I) Cumulative Regulatory Asset (Liability) = prior (I) + (H)
(J) Difference Between Contributions to Fund and Pension Cost in Rates = (D) - (L)
(K) Cumulative Regulatory Asset (Liability) in Rate Base = prior (K) + (J)
(L) Total Pension Cost Deemed Recovered in Rates = (N) + (O) if test year, otherwise no change from prior year
(M) Cumulative Total Pension Cost in Rates = prior (M) +(L)
(N) Latest Test Year NPPC - manually determined based on provisions of Pension Tracking Mechanism
(O) Amortization of Cumulative Pension Liability = Ending Pension Amount in Rate Base/5 if it is a test year, otherwise use amount from latest test year
(P) Transfers to Plant Based on NPPC in Rates = (N) * transfer rate assumption, for 1995 test year used amount from response to CA-IR-158
(Q) Pension Exp after Transfers to Plant = (N) + (O) - (P)
(R) Depreciation on Transfers to Plant = (V)/30
(S) Net Expense = (Q) + (R)
(T) Pension Amount in Rate Base = (K)
(U) Accumulated Deferred Taxes Relating to Pension in RB = (T) * composite income tax rate
(V) Accumulated Transfers to Plant = prior (V) + (P)
(W) Accumulated Depreciation Related to Accumulated Transfers to Plant = prior (W) - (R)
(X) Ending Rate Base = (T) + (U) + (V) + (W)
(Y) Test Year Revenue Requirement = (S) * revenue tax gross-up +[(prior (X) + (X)]/2 * cost of capital tax gross up [not provided for non-rate case years because pension tracker amortization recalculated only in rate cases]

Assumes rate relief with one year lag as modeling simplification (does not reflect actual historical timing of rate relief).

Hawaiian Electric Company, Inc.
"What If" calculation for response to DOD-IR-107(b) and (c)

Test Year? (A)	Year (B)	Actual NPBC (C)	less: Executive Life (D)	FAS 106 Amortization (E)	Adjusted NPBC (F)	Contributions to Trusts (G)	Cumulative Contributions to OPEB Trusts (H)	Change in OPEB Amount (I)	Cumulative OPEB Amount (J)	Difference Between OPEB Cost in Rates and Actual NPBC (K)	Cumulative Regulatory Asset (Liability) (L)	Difference Between Contributions to Fund and OPEB Cost in Rates (M)	Cumulative Regulatory Asset (Liability) in Rate Base (N)	Total OPEB Cost Deemed Recovered in Rates (O)
									3,596					
Y	1995	15,725	609	2,751	17,866	14,270	14,270	(3,596)	(0)	-	-	(369)	(369)	14,639
	1996	14,936	657	1,302	15,580	15,580	29,850	-	(0)	(930)	(930)	(930)	(1,299)	16,510
	1997	14,393	671	1,302	15,024	15,024	44,874	-	(0)	(1,486)	(2,416)	(1,486)	(2,785)	16,510
	1998	9,285	540	1,302	10,046	10,046	54,921	0	(0)	(6,464)	(8,879)	(6,464)	(9,248)	16,510
	1999	3,574	519	1,302	4,357	4,357	59,278	-	(0)	(12,153)	(21,032)	(12,153)	(21,401)	16,510
	2000	1,761	458	1,302	2,605	2,605	61,883	-	(0)	(13,905)	(34,938)	(13,905)	(35,306)	16,510
	2001	2,107	551	1,302	2,857	2,857	64,740	-	(0)	(13,653)	(48,590)	(13,653)	(48,959)	16,510
	2002	4,263	637	1,302	4,927	4,927	69,667	-	(0)	(11,583)	(60,173)	(11,583)	(60,542)	16,510
	2003	6,906	844	1,302	7,364	7,364	77,031	-	(0)	(9,146)	(69,320)	(9,146)	(69,688)	16,510
	2004	6,233	855	1,302	6,680	6,680	83,711	-	(0)	(9,830)	(79,150)	(9,830)	(79,518)	16,510
Y	2005	7,034	900	1,302	7,435	7,435	91,146	-	(0)	(9,075)	(88,224)	(9,075)	(88,593)	16,510
	2006	6,620	862	1,302	7,060	7,060	98,206	0	0	17,343	(70,881)	17,343	(71,250)	(10,283)
Y	2007	6,291	835	1,302	6,758	6,758	104,964	0	0	17,041	(53,840)	17,041	(54,208)	(10,283)
					108,560	104,964								159,172

Test Year? (A)	Year (B)	Cumulative Total OPEB Cost in Rates (P)	Latest Test Year NPPC (Q)	Amortization of Cumulative OPEB Liability (R)	Transfers to Plant Based on NPPC in Rates (S)	OPEB Exp after Transfers to Plant (T)	Depreciation on Transfers to Plant (U)	Net Expense (V)	OPEB Amount in Rate Base (W)	Accumulated Deferred Taxes Relating to OPEB in RB (X)	Accumulated Transfers to Plant (Y)	Accumulated Depreciation Related to Accumulated Transfers to Plant (Z)	Ending Rate Base (AA)	Test Year Revenue Requirement (AB)
Y	1995	14,639	16,510	-	4,953	11,557	165	11,722	(369)	144	4,953	(165)	4,563	13,191
	1996	31,149	16,510	-	4,953	11,557	330	11,887	(1,299)	505	9,906	(495)	8,617	N/A
	1997	47,659	16,510	-	4,953	11,557	495	12,052	(2,785)	1,083	14,859	(991)	12,167	N/A
	1998	64,169	16,510	-	4,953	11,557	660	12,217	(9,248)	3,599	19,812	(1,651)	12,511	N/A
	1999	80,679	16,510	-	4,953	11,557	826	12,383	(21,401)	8,327	24,765	(2,477)	9,215	N/A
	2000	97,189	16,510	-	4,953	11,557	991	12,548	(35,306)	13,738	29,718	(3,467)	4,682	N/A
	2001	113,699	16,510	-	4,953	11,557	1,156	12,713	(48,959)	19,050	34,671	(4,623)	139	N/A
	2002	130,209	16,510	-	4,953	11,557	1,321	12,878	(60,542)	23,557	39,624	(5,944)	(3,305)	N/A
	2003	146,719	16,510	-	4,953	11,557	1,486	13,043	(69,688)	27,116	44,577	(7,430)	(5,425)	N/A
	2004	163,229	16,510	-	4,953	11,557	1,651	13,208	(79,518)	30,940	49,530	(9,081)	(8,128)	N/A
Y	2005	179,739	7,435	(17,719)	2,231	(12,514)	1,725	(10,789)	(88,593)	34,471	51,761	(10,806)	(13,167)	(13,336)
	2006	169,456	7,435	(17,719)	2,231	(12,514)	1,800	(10,714)	(71,250)	27,723	53,991	(12,606)	(2,141)	N/A
Y	2007	159,172	6,758	(10,842)	2,027	(6,111)	1,867	(4,244)	(54,208)	21,092	56,019	(14,473)	8,430	(4,212)

(A) "Y" if Test Year
(B) Calendar Year
(C) Actual NPBC - per T-10 June update Attachment 11, page 3
(D) Executive Life - per T-10 June update Attachment 11, page 3
(E) FAS 106 Amortization - per T-10 June update Attachment 11, page 3
(F) Adjusted NPBC = (C) - (D) + (E)
(G) Actual Contributions to OPEB Fund - per T-10 June update Attachment 11, page 3
(H) Cumulative Contributions to OPEB Fund = prior (I) + (H)
(I) Change in OPEB Amount = (F) - (G)
(J) Cumulative OPEB Amount = prior (J) + (I)
(K) Difference Between OPEB Cost in Rates and Actual NPPC = (F) - (O)
(L) Cumulative Regulatory Asset (Liability) = prior (L) + (K)
(M) Difference Between Contributions to Fund and OPEB Cost in Rates = (G) - (O)
(N) Cumulative Regulatory Asset (Liability) in Rate Base = prior (N) + (M)
(O) Total OPEB Cost Deemed Recovered in Rates = (Q) + (R) if test year, otherwise no change from prior year
(P) Cumulative Total OPEB Cost in Rates = prior (P) +(O)
(Q) Latest Test Year NPPC - manually determined based on provisions of OPEB Tracking Mechanism
(R) Amortization of Cumulative OPEB Liability = Ending OPEB Amount in Rate Base/5 if it is a test year, otherwise use amount from latest test year
(S) Transfers to Plant Based on NPPC in Rates = (Q) * transfer rate assumption
(T) OPEB Exp after Transfers to Plant = (Q) + (R) - (S)
(U) Depreciation on Transfers to Plant = (Y)/30
(V) Net Expense = (T) + (U)
(W) OPEB Amount in Rate Base = (N)
(X) Accumulated Deferred Taxes Relating to OPEB in RB = (W) * composite income tax rate
(Y) Accumulated Transfers to Plant = prior (Y) + (S)
(Z) Accumulated Depreciation Related to Accumulated Transfers to Plant = prior (Z) - (U)
(AA) Ending Rate Base = (W) + (X) + (Y) + (Z)
(AB) Test Year Revenue Requirement = (V) * revenue tax gross-up +[(prior (AA) + (AA)]/2 * cost of capital tax gross up [not provided for non-rate case years because OPEB tracker amortization recalculated only in rate cases]

Hawaiian Electric Company, Inc.
Assumptions for "What If" calculation for response to DOD-IR-107

	Weights					Rates										
Year	ST Debt Rate	LT Debt Rate	Hybrids	Preferred Stock	Common Stock	ST Debt Rate	LT Debt Rate	Hybrids	Preferred Stock	Common Stock	Federal Tax Rate	State Tax Rate	Composite Effective Tax Rate	Composite Revenue Tax Rate	Weighted Average Revenue Requirement Factor	Reference
1995	5.46%	38.76%		6.98%	48.81%	6.00%	7.13%		7.28%	11.40%	35.00%	6.40%	38.91%	8.885%	14.30%	FInal D&O 14412
1996											35.00%	6.40%	38.91%	8.885%	0.00%	
1997											35.00%	6.40%	38.91%	8.885%	0.00%	
1998											35.00%	6.40%	38.91%	8.885%	0.00%	
1999											35.00%	6.40%	38.91%	8.885%	0.00%	
2000											35.00%	6.40%	38.91%	8.885%	0.00%	
2001											35.00%	6.40%	38.91%	8.885%	0.00%	
2002											35.00%	6.40%	38.91%	8.885%	0.00%	
2003											35.00%	6.40%	38.91%	8.885%	0.00%	
2004											35.00%	6.40%	38.91%	8.885%	0.00%	
2005	3.25%	36.81%	2.37%	1.78%	55.79%	3.30%	6.25%	7.55%	5.54%	11.00%	35.00%	6.40%	38.91%	8.885%	14.04%	Interim D&O 22050
2006											35.00%	6.40%	38.91%	8.885%	0.00%	
2007	3.08%	38.01%	2.18%	1.63%	55.10%	5.00%	6.09%	7.47%	5.51%	11.25%	35.00%	6.40%	38.91%	8.885%	14.19%	T-19 Direct

% Transferred to Plant 30% (estimate for non-rate case years)
Life of Plant 30 years

DOD-IR-108

Refer to the HECO June 2007 update for HECO T-10. Please provide all information from the HELCO case (Docket No. 05-0315) in HECO's possession and/or that is being relied upon by HECO, related to any of the following issues and including but not limited to:

a. Any settlement between HELCO and other parties in the case.
b. The Interim Decision and Order 23342 dated April 4, 2007.
c. All testimony relating to the pension tracker, pension asset, pension liability and pension expense.
d. All testimony relating to any OPEB tracker, OPEB asset, OPEB liability and OPEB expense.
e. All schedules filed in the case showing whether HELCO had a pension asset or liability, and the related amounts.
f. Whether HELCO proposed to amortize any pension asset, and the details of such amortization.
g. Any testimony relating to any proposal by HELCO to amortize a pension asset.

<u>HECO Response:</u>

a. HECO objects to this information request on the grounds that it requests documents that are already on file with the Commission and are part of the public record. The requested documents are also voluminous. Without waiving its objection, HECO will provide an electronic copy of the requested documents.

b. See the response to a.

c. See the response to a.

d. See the response to a.

e. See the response to a.

f. See the response to a.

g. See the response to a.

DOD-IR-109

In Docket 04-0113, HECO stated as follows in its reply brief: "Technically, retroactive ratemaking occurs when an additional charge (over and above that of the tariff rate then in effect) is made for past use of utility service, or the utility is required to refund revenues collected pursuant to then lawfully established rates, for such past use. Retroactive ratemaking also occurs when past deficits are made up by excessive charges in the future, or past profits are reduced by disallowances to future costs for ratemaking purposes. Response to CA-RIR-36a; Tr. (9/15) at 74-75 (Sekimura)."

a. Admit that the proposal to charge ratepayers for $5.055 million per year as shown on HECO's June 2007 update, HECO T-10, Attachment 10, page 2 of 2, runs afoul of HECO's own definition of "retroactive ratemaking."
b. If your answer to part a, is anything other than an unqualified admission, explain fully and provide supporting authority and documentation.

<u>HECO Response:</u>

a. No.

b. The $5,055,000 shown on page 2 of Attachment 10 of the HECO T-10 June 2007 Update is the test year amortization of the Company's end-of-test year prepaid pension asset. As explained in HECO T-10 (p. 75), under SFAS No. 87, a prepaid pension asset is created when fund contributions exceed the net periodic pension cost ("NPPC"). The prepaid pension asset is the net of the cumulative investor supplied fund contributions and the previously recognized pension cost. Fund contributions are the cash payments the Company has made to the pension fund over the years. Recognized pension cost is the accumulated NPPC that the Company has recognized on its income statement. Since it represents an investment in excess of the accumulated amount of pension expense previously recognized on the Company's income statement, the prepaid pension asset, like other assets, is an economic resource that has future benefit. Thus, recovery of the investment in the prepaid pension asset through the amortization does not constitute a charge for past use of utility service or to make up for a past deficit, and the inclusion of the amortization of that asset in the Company's revenue requirement does not constitute retroactive ratemaking.

DOD-IR-110

Refer to the June 2007 update for HECO T-10, Attachment 10. For all pension funding contributions made by HECO from 1999 through 2007, please identify the amount, payment date, and pension measurement year to which each such payment pertains.

HECO Response:

HECO provided detail support for the contributions made by HECO from January 1995 though December 2004 in the response to CA-RIR-33 in Docket No. 04-0113. Payments were made in the year in which the pension measurement pertains. As noted in the response to CA-IR-140 in this proceeding, HECO's contribution in 2005 of $6 million was made on December 29, 2005. HECO did not make any contributions to the pension plan in 2006 and none have been made in 2007.

DOD-IR-111

Refer to the June 2007 update for HECO T-10, Attachment 10. Where on this schedule has HECO reflected the amounts collected from ratepayers for pension expense that was included in determining HECO's revenue requirement and rates?

HECO Response:

HECO collects revenues from utility customers for services provided based on rates approved by the Commission in a ratemaking proceeding. In establishing HECO's rates in a rate case, the Commission normally considers all revenue, expense rate base and capital components for a test period in a rate case. A regulatory commission's task in a ratemaking proceeding "is to set rates which are just, reasonable, and nondiscriminatory. In discharging that task, the commission determines how much revenue the utility requires. This, in turn, leads to a determination of a fair rate of return as one component of a revenue requirement. The commission then sets rates to produce that required revenue. Once set, those rates are 'the lawful rates,' are the only rates which may be charged by the utility, and are '. . . prima facie reasonable until finally found otherwise in an action brought for that purpose.'" Potomac Electric Power Co., 83 P.U.R.3d 113, 147 (D.C. P.S.C. 1970), quoted in Consumer Advocate v. Young Brothers, Ltd., Docket No. 5140, Decision and Order No. 8686 (March 21, 1986), pages 7-8, 10-11 (in which the Commission rejected a claim that an earned rate of return in excess of the return deemed reasonable in the utility's last rate case was per se excessive.) See Decision and Order No. 16710, issued November 19, 1998 in Docket No. 97-0073 ("D&O 16710"), page 3.

See HECO's response to CA-IR-158 regarding the amount of the net periodic pension cost (NPPC) included in determining HECO's revenue requirements in prior HECO rate cases.

DOD-IR-112

Refer to HECO T-10, page 81, lines 18-21.

a. Has HECO calculated its earned rate of return or return on equity for any year from 1994 through 2006? If so, please provide such calculations.

b. In making the calculations provided in part a, does HECO remove from expenses and rate base, items that have been excluded by the Commission in rate cases? If so, please show exactly how HECO removed such items in its earned return calculations. If not, explain fully why not.

c. Please list the return on rate base and return on equity earned by HECO in each year, 2004 through 2006.

HECO Response:

a. Yes. The December 31 rate of return reports filed with the Commission for years 1995-2004 were previously provided in responses to information requests in Docket No. 04-0113 in HECO's 2005 test year rate case. See HECO's response to CA-RIR-93 for the rate of return reports for years 1995-1997 and HECO's response to DOD-RIR-28 for the rate of return reports for years 1998-2004. The December 31 rate of return reports filed with the Commission for the years 1994, 2005 and 2006 are provided in Attachment 1, pages 1-4. Two calculations of the Rate of Return on Common Equity were filed for December 2006. One calculation reflects HECO's book equity, which includes the charges to Accumulated Other Comprehensive Income ("AOCI") as a result of recording pension and postretirement benefits other than pension liabilities after implementing SFAS No. 158 on December 31, 2006. The other calculation reflects an adjustment to HECO's book equity, to exclude the amounts that were charged to AOCI.

b. Yes. The book operating income and net income are adjusted to remove items that have been excluded by the Commission in prior rate cases in calculating the ratemaking rate of returns submitted to the Commission. Rate base used in the calculation is generally determined in accordance with prior rate case decisions.

c. Please refer to part a. for the return on rate base and return on equity for 2004 through 2006 filed with the Commission.

Hawaiian Electric Company, Inc.

Rate of Return on Rate Base and on Common Equity

For the 12 months ended December 1994

(in thousands)

Line		Ratemaking This Year	Ratemaking Last Year
	Earnings for Most Recent 12 Months:		
A	Operating income	$ 60,682	$ 52,554
B	Earnings for common stock	$ 44,698	$ 36,673
	Weighted Average:		
C	Rate Base: Amount	$697,680	$660,820
D	Rate of Return (A + C)	8.70%	7.95%
E	Common Equity: Amount	$382,463	$340,546
F	Rate of Return (B + E) ...	11.69%	10.77%
	Simple Average:		
G	Rate Base: Amount	$706,272	$659,008
H	Rate of Return (A + G)	8.59%	7.97%
I	Common Equity: Amount	$388,686	$348,486
J	Rate of Return (B + I) ...	11.50%	10.52%
	End of Period:		
K	Rate Base: Amount	$728,620	$683,923
L	Rate of Return (A + K)	8.33%	7.68%
M	Common Equity: Amount	$405,655	$371,716
N	Rate of Return (B + M) ...	11.02%	9.87%

2/02/95

HAWAIIAN ELECTRIC COMPANY, INC.

RATE OF RETURN ON RATE BASE AND ON COMMON EQUITY
For the 12 months ended December 31,

(In thousands)

Line		Ratemaking 2005	Ratemaking 2004
	Earnings for most recent 12 months:		
A	Operating income	$69,544	$75,400
B	Earnings for common stock	$44,843	$52,051
	Weighted Average:		
C	Rate Base: Amount	$1,119,418	$1,018,110
D	Rate of Return (A/C)	6.21%	7.41%
E	Common Equity: Amount	$649,812	$606,929
F	Rate of Return (B/E)	6.90%	8.58%
	Simple Average:		
G	Rate Base: Amount	$1,121,604	$1,058,206
H	Rate of Return (A/G)	6.20%	7.13%
I	Common Equity: Amount	$648,423	$612,894
J	Rate of Return (B/I)	6.92%	8.49%
	End of Period:		
K	Rate Base: Amount	$1,140,111	$1,103,097
L	Rate of Return (A/K)	6.10%	6.84%
M	Common Equity: Amount	$655,748	$641,097
N	Rate of Return (B/M)	6.84%	8.12%

Per Interim Decision and Order No. 22050 dated September 27, 2005, the Commission utilized a rate of return on average rate base of 8.66% including a return on average common equity of 10.70%, in determining HECO's revenue requirements.

Per Decision and Order No. 14412 dated December 11, 1995, the allowed rate of return on average rate base and on average common equity is 9.16% and 11.40%, respectively.

HAWAIIAN ELECTRIC COMPANY, INC.

RATE OF RETURN ON RATE BASE AND ON COMMON EQUITY
For the 12 months ended December 31,

(In thousands)

Line		Ratemaking 2006	Ratemaking 2005
	Earnings for most recent 12 months:		
A	Operating income	$77,559	$69,544
B	Earnings for common stock	$51,038	$44,843
	Weighted Average:		
C	Rate Base: Amount	$1,164,670	$1,119,418
D	Rate of Return (A/C)	6.66%	6.21%
E	Common Equity: Amount	$661,696 *	$649,812
F	Rate of Return (B/E)	7.71%	6.90%
	Simple Average:		
G	Rate Base: Amount	$1,144,768	$1,121,604
H	Rate of Return (A/G)	6.78%	6.20%
I	Common Equity: Amount	$623,052 *	$648,423
J	Rate of Return (B/I)	8.19%	6.92%
	End of Period:		
K	Rate Base: Amount	$1,149,425	$1,140,111
L	Rate of Return (A/K)	6.75%	6.10%
M	Common Equity: Amount	$590,356 *	$655,748
N	Rate of Return (B/M)	8.65%	6.84%

Per Interim Decision and Order No. 22050 dated September 27, 2005, the Commission utilized a rate of return on average rate base of 8.66% including a return on average common equity of 10.70%, in determining HECO's revenue requirements.

Per Decision and Order No. 14412 dated December 11, 1995, the allowed rate of return on average rate base and on average common equity is 9.16% and 11.40%, respectively.

* The common equity amounts reflect HECO's book equity, which includes the charges to Accumulated Other Comprehensive Income (AOCI) as a result of recording a pension and other postretirement benefits liability after implementing SFAS No. 158, on December 31, 2006.

HAWAIIAN ELECTRIC COMPANY, INC.

RATE OF RETURN ON RATE BASE AND ON COMMON EQUITY
(Excludes AOCI charges due to SFAS No. 158 from Common Equity)
For the 12 months ended December 31,

(In thousands)

Line		Ratemaking 2006	Ratemaking 2005
	Earnings for most recent 12 months:		
A	Operating income	$77,559	$69,544
B	Earnings for common stock	$51,038	$44,843
	Weighted Average:		
C	Rate Base: Amount	$1,164,670	$1,119,418
D	Rate of Return (A/C)	6.66%	6.21%
E	Common Equity: Amount	$668,986 *	$649,812
F	Rate of Return (B/E)	7.63%	6.90%
	Simple Average:		
G	Rate Base: Amount	$1,144,768	$1,121,604
H	Rate of Return (A/G)	6.78%	6.20%
I	Common Equity: Amount	$670,434 *	$648,423
J	Rate of Return (B/I)	7.61%	6.92%
	End of Period:		
K	Rate Base: Amount	$1,149,425	$1,140,111
L	Rate of Return (A/K)	6.75%	6.10%
M	Common Equity: Amount	$685,120 *	$655,748
N	Rate of Return (B/M)	7.45%	6.84%

Per Interim Decision and Order No. 22050 dated September 27, 2005, the Commission utilized a rate of return on average rate base of 8.66% including a return on average common equity of 10.70%, in determining HECO's revenue requirements.

Per Decision and Order No. 14412 dated December 11, 1995, the allowed rate of return on average rate base and on average common equity is 9.16% and 11.40%, respectively.

* The common equity amounts reflect an adjustment to HECO's book equity, to exclude the amounts that were charged to Accumulated Other Comprehensive Income (AOCI) as a result of recording a pension and other postretirement benefits liability after implementing SFAS No. 158, on December 31, 2006.

DOD-IR-113

Refer to HECO T-1, page 41, and to the Pension Funding Study that HECO filed with the Commission on or about May 30, 2007, per the directive of the Commission in the AOCI docket (Docket No. 05-0310).

a. Was HECO's assumption of a 3 year period between rate cases utilized in the Pension Funding Study? If not, explain fully why not.

b. Was a five-year period between rate cases assumed for HECO in the Pension Funding Study? (Attachment 3, page 1 of 31 of the Pension Funding Study states that for HECO a rate case is assumed in the initial year – 2007 for HECO – and "every five years thereafter.") Explain fully the basis for the "major assumption" that HECO would have a rate case every five years.

c. Refer to Attachment 3, page 2 of 31 of the Pension Funding Study. Explain fully how each of the "TY Pension Exp before Trar" (P1) amounts were determined, and why such amounts change after Year 4.

d. Refer to Attachment 3, page 2 of 31 of the Pension Funding Study. Explain why the "Initial" Year and "Year 5" are assumed to be a "Rate Year."

e. Is the Company's pension funding policy in any way impacted by the ratemaking treatment of the pension asset? If so, please explain fully how the Company's pension funding policy is impacted by the ratemaking treatment of the pension asset.

f. Would the Company's pension funding policy be any different if the Commission were to determine that the pension asset does not belong in rate base? If so, please explain fully how the Company's pension funding policy would be impacted by the ratemaking treatment of the pension asset under such an outcome.

g. Is the Company's pension funding policy in any way impacted by the ratemaking treatment of the amortization of the pension asset? If so, please explain fully how the Company's pension funding policy is impacted by the ratemaking treatment related to the amortization of the pension asset.

h. Would the Company's pension funding policy be any different if the Commission were to determine that HECO's proposed amortization of the pension asset does not belong in operating expenses? If so, please explain fully how the Company's pension funding policy would be impacted by such ratemaking treatment.

i. Is the Company's pension funding policy in any way impacted by whether a pension tracking mechanism is approved or not? If so, please explain fully how the Company's pension funding policy is impacted by whether a pension tracking mechanism is, or is not approved.

j. Would the Company's pension funding policy be any different if the Commission were to reject HECO's proposed pension tracking mechanism? If so, please explain fully how the Company's pension funding policy would be impacted if HECO's proposed pension tracking mechanism were rejected.

k. Is it HECO's opinion that the pension funding policy described in Attachment 1 to the Pension Funding Study will minimize the revenue requirement to ratepayers in the current HECO rate case? If so, please demonstrate how this is achieved. If not, explain fully why not.

l. Is it HECO's opinion that the pension funding policy described in Attachment 1 to the Pension Funding Study will minimize the revenue requirement to ratepayers over a series of HECO's anticipated future rate cases? If so, please demonstrate how this is achieved. If not, explain fully why not.

HECO Response:

a. One scenario for HECO was based on rate cases every three years. The assumptions for the scenarios were:

Company	Attachment 2 Pages	Attachment 3 Pages	Initial Year	Years Assumed Between Rate Cases	Test Years Assumed
HECO	18, 26-31	2-7	2007	5	2007, 2012
HELCO	17, 20-25	8-13	2006	5	2006, 2011
MECO	19, 32-37	14-19	2007	5	2007, 2012
HECO	N/A	20-25	2007	3	2010, 2013,2016
HECO	N/A	26-31	2007	5	2007, 2012

Other scenarios were based on rate cases every 5 years, based on the 5 year amortization period for pension asset proposed by the Consumer Advocate in HELCO's 2006 test year rate case (Docket No. 05-0315) for the pension tracking mechanism.

b. See response to (a).

c. Column P1 is the test year pension expense before transfers to plant. It is calculated as the test year NPPC (see column E in corresponding scenario in Attachment 2, page 26 of 68) + 5 year amortization of the test year ending regulatory asset and liability (see columns K and M in corresponding scenario in Attachment 2, page 26 of 68). It changes only in a test year.

d. See response to (a).

e. Ratemaking treatment of the pension asset could impact the Company's pension funding policy, because pension funding requires the use of investor-provided funds and ratemaking treatment could determine whether or not those investor-provided funds earn an adequate return.

f. The Company's pension funding policy could change if the Commission were to determine that the pension asset can not be included in determining rate base. If the investor-funded pension asset is not allowed in rate base, those investor-provided funds will not have the opportunity to earn an adequate return, which may result in a reevaluation of the pension funding policy to reduce the amount of investment in pension asset.

g. The Company's pension funding policy could change if investors are not allowed a return of and/or a return on investor-provided funds. The amortization of the pension asset results from the implementation of the pension tracking mechanism. If the ratemaking treatment of the amortization of the pension asset results in investor-provided funds not being recoverable in future rates, it may result in a reevaluation of the pension funding policy to reduce the amount of investment in pension asset.

h. See response to (g).

i. The Company does not foresee any change in its pension funding policy resulting solely from the determination of whether the pension tracking mechanism is adopted or not. However other ratemaking determinations, as discussed above, may impact the pension funding policy. See responses to parts (e) and (f).

j. See response to (i).

k. No, it is not HECO's position that the pension funding policy minimizes revenue requirements in this rate case. The development of the pension funding policy considered the impact of the policy on revenue requirements over a study period rather than focusing on minimizing the revenue requirements in any specific rate case. Further, the impact of the pension funding policy in 2007 was not included in the scope of the Pension Funding Study; therefore the Company did not assess the impact of different pension funding policies on the HECO 2007 test year. The test year identified in the study (2007 for HECO) is the "initial year" of the study and the test year does not assume any difference in pension funding (i.e. in the "initial year", the pension funding is not being compared).

l. The pension funding policy described in Attachment 1 to the Pension Funding Study balances benefit security, funding flexibility, stability and predictability of contribution requirements, impact on electric rates, and the funded status of the pension funds as discussed by Watson Wyatt on pages 9 and 10 in Attachment 2 to the Pension Funding Study. As noted by Watson Wyatt (on page 18 of 68 in Attachment 2), revenue requirements for HECO over the study period under the baseline economic scenario are projected to be slightly lower under NPPC funding policy compared to the minimum required contribution ("MRC") funding policy. Additionally, the NPPC funding policy is expected to result in smoother and more predictable funding.

DOD-IR-114

Attachment 1 of the Pension Funding Study at page 1 of 3 states that one of the purposes of the study is to "evaluate the impact on ratepayers of various funding alternatives for the utility portion of the Pension Plan."

a. Please clearly identify and explain which funding alternative that was evaluated in the study produces the least revenue requirement for ratepayers.

b. Please identify exactly where in the study the results of the optimal pension funding alternative, and the revenue requirement impacts of this on ratepayers is shown.

c. Has HECO adopted as its pension funding policy, the funding alternative described in the response to part a? If not, explain fully why not.

<u>HECO Response:</u>

a. The HECO revenue requirement comparisons are summarized on page 18 of 68 of Attachment 2 (Table A-2) of the Pension Funding Study. The funding alternative which produces the lower revenue requirement for each economic scenario is indicated below:

Economic Scenario	Total	NPV
Baseline	NPPC	NPPC
Less Favorable	NPPC	NPPC
More Favorable	MRC	MRC

b. See response to (a). Support for these revenue requirement calculations was provided on pages 26-31 of Attachment 2 and pages 2-7 of Attachment 3 of the Pension Funding Study.

c. Yes, the Company's policy is generally to fund NPPC (subject to funding limits and target funded status), which was the funding alternative which produced the lower revenue requirements in the baseline economic scenario. The Company's pension funding policy is:

> "Contribute at least the net periodic pension cost as calculated using FAS 87 during the fiscal year, subject to statutory funding limits and targeted funded status as determined in consultation with the actuary. When no pension tracking mechanism has been approved by the PUC and when cumulative contributions exceed the cumulative pension costs recognized for financial statement purposes, the Companies may limit contributions to the pension fund. When a pension tracking mechanism has been approved by the PUC, funding of the pension fund will be in accordance with the pension tracking mechanism requirements. Contributions will not be less than the ERISA minimum funding requirements and will not exceed the maximum tax deductible amount on an accrual basis."

DOD-IR-115

Refer to Attachment 2 of the Pension Funding Study, page 18 of 68. Show in detail how each of the HECO revenue requirement amounts were calculated:

a. $31.067 million in all 3 scenarios for years 1-4.

b. $7.231 and $8.424 million per year for years 5-10 in baseline scenario.

c. $23.471 and $33.178 million per year for years 5-10 in the "less favorable economic scenario."

d. $1.287 and -$2.531 million per year for years 5-10 in the "more favorable economic scenario."

HECO Response:

a. The supporting calculations for the revenue requirements summarized on page 18 of 68 are provided on pages 2-7 of 31 in Attachment 3. Attached on page 2 of this response are assumptions which were inadvertently omitted from the Pension Funding Study filing.

A summary of the $31.067 million calculation is as follows:

Test Year Expense before Transfers to Plant	$18,400
Pension Asset Amortization	9,972
Transfer to Plant	(5,520)
Revenue Taxes on Net Expense	
($18,400+9,972-5,520) * (1/(1-8.885%) – 1)	2,228
Revenue Requirement on Average Rate Base	
($41,700+35,980)/2 * 15.413%	5,986
Total Revenue Requirement	$31,066

There is a slight difference due to rounding.

b. See pages 2 and 3 of 31 in Attachment 3.

c. See pages 4 and 5 of 31 in Attachment 3.

d. See pages 6 and 7 of 31 in Attachment 3.

Assumptions

Cost of Capital Assumptions:	Weight	Rate	Weighted Average	After-tax Weighted Average	Weighted Average Revenue Requirement
ST Debt	3.00%	6.00%	0.180%	0.110%	0.198%
LT Debt	36.00%	6.50%	2.340%	1.430%	2.568%
Preferred Stock	7.00%	8.00%	0.560%	0.560%	1.006%
Common Stock	54.00%	12.00%	6.480%	6.480%	11.642%
			9.560%	8.579%	15.413%

Tax Assumptions:		
Federal	35.00%	32.89%
State	6.40%	6.02%
		38.91%

Public Service Company Tax	5.885%	(on gross receipts)
PUC Fee	0.500%	(on gross receipts)
Franchise Tax	2.500%	(on electricity sales)
Revenue Tax Rate	8.885%	
Discount Rate	9%	
% Transferred to Plant	30%	
Life of Plant	30	years

DOD-IR-116

Refer to Attachment 2 of the Pension Funding Study, pages 26-31 of 68.

a. What is the basis for the 9% discount rate assumption? Show supporting calculations.

b. What is the basis for the $9.972 Prepaid in Column C? Show supporting calculations.

c. Referring to note C, show in detail how the "cumulative net benefit to ratepayers at initial year" was determined. Identify all assumptions that were made in evaluating whether ratepayers had any benefit at the initial year, and the basis for determining the amount of such benefit.

HECO Response:

a. The 9% is an approximation of the weighted-average after tax cost of capital assumption (8.579%) used in the analysis. See response to DOD-IR-115, page 2 of 2.

b. The $9,972,000 is based on a 5-year amortization of the ending pension asset in the prior year ($49,860,000/5).

c. See response to (b). The amounts in column (C) are based on the amortization of the pension asset. The benefits to ratepayers from the pension asset were discussed extensively in T-10 in this docket and in RT-16 in Docket No. 04-0113.

DOD-IR-117

Refer to Attachment 3 of the Pension Funding Study.

a. Why are there no amounts for any of the HECO scenarios on the “Year 10” line? Explain fully.

b. Using the assumptions made by HECO, is its pension expense anticipated to be non-existent after Year 9 under all of the HECO scenarios shown in Attachment 3 of the Pension Funding Study? What is the basis for making such an assumption? Explain fully.

c. Does HECO plan do discontinue all of its defined benefit pension plans after “Year 9” in the Pension Funding Study? If so, explain fully the basis for such an assumption. If not, explain fully why not.

HECO Response:

a. The Companies requested a 10-year projection of pension costs and funding requirements. For all Companies, the 10-year period was 2007-2016. In HELCO’s case, the initial year was 2006, which was HELCO’s test year; therefore, year 1-10 were projected. In HECO and MECO’s cases, the initial year was 2007, since 2007 is the test year for HECO and MECO. As a result, the initial year and years 1-9 were projected and no data was provided for year 10.

b. No, HECO expects pension costs beyond year 9, however the study period for HECO ended in year 9.

c. See responses to (a) and (b).

DOD-IR-118

Refer to Attachment 2, pages 56-68 of 68 of the Pension Funding Study.

a. Has Watson Wyatt ever advised a pension client to convert a defined benefit plan to another type of retirement plan, such as a defined contribution plan, in order to limit risk? If not, explain fully why not.

b. Is Watson Wyatt aware of any instances in which companies have converted a defined benefit plan to another type of retirement plan, such as a defined contribution plan? If so, please describe such instances and the factors which led to such conversions.

c. Did Watson Wyatt provide any advice to HECO or HECO's affiliates concerning making changes in any of the following areas that Watson Wyatt identified (on page 58 of 68) as "strategies for responding" to the Pension Protection Act: (1) plan design, (2) asset allocation, or (3) actuarial assumptions and methods?

d. If the answer to an item in part c is affirmative, please identify and explain fully the advice provided.

e. Refer to page 63 of Attachment 2. Does HECO's plan contain any "early retirement subsidies"? If so, please identify, quantify and explain such subsidies.

f. Refer to page 63 of Attachment 2. Has HECO included any cost in the test year for any Nonqualified Deferred Compensation Plans of itself or affiliates? If so, please identify, quantify and explain fully all such costs, and identify the amounts in each account.

g. Refer to page 67 of 68. Which of the "Short-term funding considerations" is HECO implementing and why? Explain fully.

HECO Response:

a. The Company is not privy to what Watson Wyatt has advised its other pension clients regarding converting a defined benefit plan to another type of retirement plan, such as a defined contribution plan, in order to limit risk. Watson Wyatt's advice to other clients would be confidential.

b. HECO does not know whether Watson Wyatt has knowledge of companies that have converted a defined benefit plan to another type of retirement plan, such as a defined contribution plan. However the circumstances for such conversion would need to consider the specific circumstances related to the companies that made such a conversion. With regard to HECO, such conversion would need to consider the specific requirements and circumstances of its defined benefit plan, such as the requirements under its collective bargaining agreement.

c. The information provided by Watson Wyatt to HECO or HECO's affiliates regarding strategies for responding to the Pension Protection Act is the information provided on page 58 of Attachment 2 to the Pension Funding Policy Study. The information provided was of a general nature, and not specific regarding strategies for HECO or HECO's affiliates.

d. Not applicable.

e. HECO has early retirement provisions in its pension plan. The early retirement provisions of the plan are described in HECO-WP-1251, pages 31-32. Early retirement "subsidies" have not been quantified since HECO's pension plan is not projected to be "at risk" by failing to meet funding threshholds described on page 63 of Attachment 2 to the Pension Funding Study. See also pages 50-55 of Attachment 2 to the Pension Funding Study for projected funding levels under the funding policy alternatives.

f. The costs of the nonqualified pension plans have been removed from the test year estimates as discussed in HECO T-12, page 15. HECO T-12 states, "In order to limit the issues in this proceeding, non-qualified pension expense has been deleted from the test year expenses, as shown in HECO-1201, column h." Further as discussed in response to DOD-IR-130, HECO has removed from the test year estimates, expenses related to restricted stock and stock based compensation, stock options, and incentive compensation from the test year.

g. The information on page 67 of Attachment 2 to the Pension Funding Study was a general presentation of short-term funding considerations for defined benefit plans, and not specifically related to HECO or its affiliates. The information presented was with regard to what a company may want to consider if they have an underfunded plan. For HECO, as of January 1, 2007, the plan is over 100% funded on a current liability basis, so there is no special short-term funding consideration needed for the plan to avoid adverse circumstances with regard to funding requirements under the Pension Protection Act. HECO will generally be targeting the third block listed on the slide, primarily because HECO is generally at that level.

DOD-IR-119

Refer to HECO T-6 at page 37, lines 19-24. Please state the number of actual PSO&M Department filled positions for each category as of June 30, 2007.

HECO Response:

Actual PSO&M Department filled positions for each category as of June 30, 2007, are summarized below:

Operation Division	151
Maintenance Division	145
Planning Division	21
Manager and Staff	11
Total	328

The total of 328 agrees with the employee count provided in HECO's response to CA-IR-465, Actual Employee Count vs. 2007 EOY Test Year Employee Count as of June 30, 2007 for the Power Supply Operation & Maintenance Department. See also CA-IR-414, Attachment 1 for additional details.

DOD-IR-120

Refer to HECO T-7 at page 70.

a. What is the actual contribution (was estimated by HECO at $675,000) and when was it paid?

b. What is the service period of the DSG unit?

c. Provide a copy of the DSG contract.

d. The June 2007 Update for HECO T-17, pages 7 and 9 of 18 show zero for the "Unamortized DSG Regulatory Asset." Is this the same item discussed at HECO T-7, pages 70-71? If not, explain fully.

e. Refer to the June 2007 Update for HECO T-6. Please reconcile the expenses for the cancelled Kaiser DSG project being removed in the amount of $54,600 (on pages 2-3 of the update) with the $30,000 mentioned on page 71, line 10 of T-10. Identify, quantify and explain each reconciling item.

HECO Response:

Note that DOD reference to HECO T-7 at page 70 should actually be to HECO T-6 at page 70 and in subpart d., HECO T-7, pages 70-71 should actually be to HECO T-6, pages 70-71, in accordance with errors and corrections acknowledged by the Department of the Navy, Office of the General Counsel in a letter date July 12, 2007.

a. The Kaiser DSG project was cancelled as described in HECO's responses to CA-IR-237, CA-IR-337, and CA-IR-484 and in the HECO T-6 June 2007 Update, page 2. As a result, HECO's contribution to the costs for the installation of paralleling switchgear is $0.

b. This question is not applicable as the project was cancelled.

c. This question is not applicable as the project was cancelled.

d. Yes, it is the same item.

e. The expenses of $54,600 being removed in the June 2007 Update for the Kaiser DSG project and the $30,000 amortization amount in the test year are distinctly separate items and do not reconcile. The $54,600 represents O&M non-labor expense related to the DSG project as shown in the June 2007 Update, pages 2 and 3. The $30,000 represents the amortization of the paralleling switchgear equipment that was identified in HECO-628 and described in HECO T-6, pages 70 and 71. The $30,000 amortization expense was effectively removed from Other Production O&M expense by a calculation error in the response to CA-IR-3, Attachment 1, page 1. In CA-IR-3, Attachment 1, page 1, the "901-Amort" amount of $30,000 was included as a line item and was erroneously included in the proposed adjustment to the test year estimate that totaled a reduction of $155,000. Accordingly, the proposed downward adjustment of $155,000 should have been only $125,000 (i.e., $155,000 - $30,000). If the $30,000 had not been erroneously included in the proposed adjustment as part of the response to CA-IR-3, it would have been proposed at this time, coincident with the confirmation of the cancellation of the Kaiser DSG project.

The calculation error was a result of mistakenly confusing the 901-amortization amount of $30,000 and the DSG Incentive amount of $24,600 as one and the same in CA-IR-3, Attachment 1. The corrected CA-IR-3, Attachment 1 would appear as shown in Attachment 1 to this response.

2007 Rate Case - Distributed Generation (Includes DSG)
Production Dept - Non-Labor
(In Thous)

	Pillar	9/22/06 DG O&M Sch	Diff	
570- Rental	$2,916	$2,771	$145	~~(Incl 901 Amort)~~
201- Material	$16	$29	($13)	
501- O/S	$406	$413	($7)	
~~901- Amort~~	~~$30 (1)~~	~~$0~~	~~$30~~	
Total	~~$3,368~~ $3,338	$3,213	~~$155~~ $125	Rate Case Adj

~~NOTES:~~
~~(1) Represent the 2007 amortization for the Kaiser DSG paralleling switchgear contribution to be amortized over the period the ratepayer will benefit from the contribution. See further explanation in HECO T-6 pages 69 - 71.~~

DOD-IR-121

Ref: Smart Signal, $897,000. Refer to HECO T-6 at page 80.

a. What is the useful life of Smart Signal?
b. What annual savings in maintenance does HECO expect from Smart Signal? Include calculations and estimates.
c. Did HECO prepare any type of cost-benefit analysis relating to Smart Signal? If so, please provide it.
d. Provide all invoices for Smart Signal.
e. If the invoices in part d do not add up to $897,000, please identify, quantify and explain all differences.
f. Is HECO aware of any other utilities that have installed Smart Signal?
g. If the answer to part f is affirmative, please identify the utilities and the year that each installed Smart Signal.
h. Has Smart Signal been in use at any utility for more than a three year period? If so, please identify all instances of which HECO is aware.
i. Does HECO anticipate that Smart Signal will still be functioning beyond the end of its proposed three-year amortization period? If not, explain fully why not. If so, provide the basis for such anticipation.
j. Does HECO have a "Project Identification Form – Authorize Project" type document (see, e.g., CA-IR-307 Attachment 5 for examples) for Smart Signal? If so, please provide it. If not, explain fully why not.

HECO Response:

a. Smart Signal is one of several commercially available products and services for enhanced equipment condition monitoring (ECM) and enhanced performance monitoring of electric utility power plants. These systems continuously monitor the operational parameters for selected equipment in the power plant on a real-time basis and analyze values and trends for these parameters to determine if the equipment is operating within normal bounds. The benefits of these systems are achieved through early detection of incipient equipment failures such that the required maintenance can be completed on a scheduled rather than an emergency basis. Thus, the benefits are realized by avoiding unknown, future events. The utility maintenance programs within which such systems are used are called predictive maintenance or condition-based maintenance programs.

The useful life of Smart Signal (as well as other commercially available ECM products and services) depends on several factors including the service and support commercial arrangements with the vendor, the extent to which the ECM system was serviced and supported using in-house resources, and the functional life of the underlying IT software and hardware infrastructure. Due to the unknown influences of these factors, no fixed number for the "service life" for an ECM system can be provided at this time. One of the objectives of the pilot-scale ECM projects being considered by HECO is to gain a better understanding of the useful lives of these products and services.

The use of enhanced equipment condition monitoring systems and enhanced performance monitoring systems as part of a utility's predictive maintenance program is becoming general practice within the electric utility industry. This is evidenced by widespread implementation of such systems and the proliferation of commercially available products and services for such systems.

HECO initiated an evaluation of enhanced ECM systems in early 2005. Based on information from the Electric Power Research Institute, other utilities and the various vendors of enhanced ECM systems, HECO decided to conduct a pilot project to evaluate the Smart Signal system on one of the HECO generating units. This project was initiated in early 2006. In parallel with this pilot project of the Smart Signal system, HECO continued to evaluate other ECM products and services.

A "Business Case for Smart Signal Project" narrative for the pilot project evaluation of Smart Signal was prepared by the HECO Power Supply Engineering staff in April 2006, and is provided as Attachment 1 to CA-IR-81. HECO did not perform any detailed quantitative benefit/cost analysis other than the high level analysis of "avoided costs" for historical equipment failures experienced at HECO. The primary driver for initiating this effort was the observed emergence of enhanced ECM as general practice for predictive maintenance programs within the electric utility industry.

The pilot project evaluation of the Smart Signal product was completed in late February 2007. While the technical results of the evaluation were promising, HECO has decided to not pursue further implementation of the Smart Signal ECM product due to commercial issues. The primary issue involves Smart Signal's refusal to provide pricing based on incremental implementation of their product for specific categories of equipment across all generating units versus "vertical implementation" for each generating unit based on megawatts. It is HECO's assessment that the implementation path required by the Smart Signal company does not allow for the most cost-effective implementation of an enhanced ECM system at HECO.

HECO is continuing the evaluation of other commercially available enhanced ECM products that was underway in parallel with the Smart Signal evaluation pilot project. HECO anticipates the completion of this evaluation and the implementation of an enhanced ECM system by fourth quarter 2007 or first quarter of 2008..

b. As described in the response to subpart a, HECO will not be pursuing Smart Signal. At this time no annual savings for maintenance have been calculated from Smart Signal, and HECO has not incorporated any potential savings from Smart Signal or other ECM system in the 2007 test year estimate.

c. As stated in the HECO response to subpart a, HECO did not perform any quantitative benefit/cost analysis other than the high level analysis of "avoided costs" for historical equipment failures experienced at HECO. The primary driver for HECO's consideration of ECM products and services was the observed emergence of enhanced ECM as general practice for predictive maintenance programs within the electric utility industry.

During the course of the Smart Signal pilot project, Smart Signal representatives prepared a presentation on the benefits (i.e., avoided future costs due to equipment failures) based on a statistical analysis of historical EFOR and EAF data for HECO's Kane 5. A copy of the presentation is provided as Attachment 2 to CA-IR-81. The Smart Signal presentation was not the product of a rigorous analysis and included questionable assumptions not applicable to HECO. For these reasons, it is HECO's assessment that the Smart Signal analysis significantly overstates benefits that may be realized on the HECO system from the implementation of an enhanced ECM system as part of the HECO predictive maintenance program.

d. The invoices for the Smart Signal pilot project are provided as Attachment 1 to this response.

e. The invoices to date for the Smart Signal pilot project total $123,417. Of this amount, $111,417 was incurred in 2006, and $12,000 was incurred in 2007. As noted in the response to CA-IR-81, (a) the pilot project evaluation of the Smart Signal product was completed in late February 2007, (b) HECO decided to not pursue further implementation of the Smart Signal enhanced equipment condition monitoring (ECM) product at this time due to commercial issues, (c) HECO is continuing the evaluation of other commercially available enhanced ECM products that was underway in parallel with the Smart Signal evaluation pilot project, and (d) HECO anticipates the completion of this evaluation and the implementation of an enhanced ECM system by fourth quarter 2007.

A portion of the funds originally earmarked for the fleetwide deployment of the Smart Signal technology is being used to fund a pilot project for an alternative ECM product and service being offered by Black & Veatch (B&V). The B&V pilot program is expected to begin on or about August 1, 2007, and be completed in January 2008. The estimated cost for the B&V products and services for the pilot program is $78,000, and approximately $70,000 of the cost will be incurred in 2007. The accompanying costs to implement a secure information technology (IT) interface are estimated to be $15,000. Thus, the total costs now anticipated to be expended in 2007 for ECM products and services are as follows:

Smart Signal (Jan & Feb 2007 pilot program)	$12,000
B&V (Aug through Dec 2007 pilot program)	70,000
IT interface for B&V pilot program	15,000
TOTAL	$97,000

In HECO T-6, HECO noted that the 2007 O&M budget included $897,000 for installing Smart Signal across the HECO generating fleet in 2007. HECO proposed a normalization adjustment of $599,000 to amortize the cost over three years, so that the 2007 test year expense estimate would be $299,000. HECO is removing the $299,000 normalized estimate for Smart Signal from the test year O&M expense estimate, and adding back $97,000, for a net adjustment of $(202,000).

f. Yes, please refer to the response to subpart g for additional detail.

g. Based on the information provided by Smart Signal, the utilities and IPPs of which HECO is aware that have implemented the Smart Signal ECM system are listed below. We do not have any information on the dates of these Smart Signal ECM system implementations. Since we terminated the pilot project with Smart Signal in February 2007, this list may not include installations completed since that date.

- Allegheny Power
- Mirant
- Panhandle Energy
- Arizona Public Service Nuclear
- PPL
- Progress Energy
- Calpine
- Reliant
- DTE Energy
- Dynegy Midwest Generation
- TransAlta
- TXU (Texas Utilities)
- Wisconsin Public Service
- WE Energies
- Kansas City Power & Light
- Keyspan
- Xcel Energy

h. Since HECO does not have information on when the Smart Signal system installations listed in response to subpart g were completed for these utilities and IPPs, we are unable to identify installations that have been in service for more than three years.

i. Since HECO terminated the pilot project for the Smart Signal system in February 2007, the question of whether the Smart Signal system will be functioning beyond the end of its proposed three-year amortization period is moot.

j. The Project Identification Form (PIF) for the fleet-wide deployment of Smart Signal is provided as Attachment 13D, pages 45 to 49 to HECO T-6. However, as stated in the response to subpart a above, the Smart Signal project was terminated after the pilot project evaluation and the actual expenditures on Smart Signal are significantly less than the PIF amount.

SmartSignal

901 Warrenville Road
Suite 300
Lisle, IL 60532

Invoice

DATE	INVOICE NO.
2/28/2006	1590

BILL TO
Hawaiian Electric Company, Inc. PO Box 2750 Honolulu, HI 96840 Attn: Brenner Munger

P.O. NO.	TERMS	REP
PYA06008010101	Net 30	GW

ITEM	DESCRIPTION	RATE	QTY	AMOUNT
Smart Start D	50% of IT Hosting & Data Feed Setup Fee upon receipt of purchase order PYA-06-008-01-01-01	57,000.00	0.5	28,500.00

APPROVED FOR PAYMENT
BY: Brenner Munger
DATE 3/28/06
MIMS CONTRACT # PYA-06-008-01-01-01
Payment Amt: $28,500.00

Please remit to above address or use wiring instructions--payable in US dollars	**Total**	$28,500.00

SmartSignal

Invoice

901 Warrenville Road
Suite 300
Lisle, IL 60532

DATE	INVOICE NO.
5/17/2006	1621

BILL TO

Hawaiian Electric Company, Inc.
PO Box 2750
Honolulu, HI 96840
Attn: Brenner Munger

P.O. NO.	TERMS	REP
PYA06008010101	Net 30	GW

ITEM	DESCRIPTION	RATE	QTY	AMOUNT
travel expenses	Travel expense for George Hermanas for kickoff meeting 3/5/06-3/11/06	763.61		763.61
travel expenses	Travel expenses for Bill Nieman the week of 3/26/06-3/31/06	1,153.82		1,153.82

APPROVED FOR PAYMENT
BY: [signature]
DATE 5/23/06
MIMS CONTRACT # PYA06008.01.01.01
Payment Amt: $1,917.43

Please remit to above address or use wiring instructions--payable in US dollars

Total $1,917.43

SmartSignal

901 Warrenville Road
Suite 300
Lisle, IL 60532

Invoice

DATE	INVOICE NO.
5/22/2006	1623

BILL TO
Hawaiian Electric Company, Inc. PO Box 2750 Honolulu, HI 96840 Attn: Brenner Munger

P.O. NO.	TERMS	REP
PYA06008010101	Net 30	GW

ITEM	DESCRIPTION	RATE	QTY	AMOUNT
Smart Start D	50% of IT Hosting & Data Feed Setup Fee upon live monitoring established 5/15/06 PYA-06-008-01-01-01	57,000.00	0.5	28,500.00
Smart Start D	On site workbench and watchlist training performed on 5/2 - 5/4/06	7,500.00	1	7,500.00
Smart Start D	Live monitoring for the period 5/15/06-6/14/06. Live monitoring established on 5/15/06	6,000.00	1	6,000.00
	Purchase order PYA-06-008-01-01-01			

pyh APPROVED FOR PAYMENT
BY: Brenner Munger
DATE 6/19/06
MIMS CONTRACT # PYA-06-008-01-01-01
Payment Amt: $42,000.00

Please remit to above address or use wiring instructions--payable in US dollars

Total $42,000.00

SmartSignal

Invoice

901 Warrenville Road
Suite 300
Lisle, IL 60532

DATE	INVOICE NO.
6/1/2006	1630

BILL TO

Hawaiian Electric Company, Inc.
PO Box 2750
Honolulu, HI 96840
Attn: Accounts Payable

P.O. NO.	TERMS	REP
PYA06008010101	Net 30	GW

ITEM	DESCRIPTION	RATE	QTY	AMOUNT
Smart Start D	Live monitoring for the period of 6/15/06-7/14/06.	6,000.00	1	6,000.00

WMA APPROVED FOR PAYMENT
BY: Verna Munge
DATE 6/20/06
MIMS CONTRACT # PYA-06-008-01-01-01
Payment Amt: $6,000.00

Please remit to above address or use wiring instructions--payable in US dollars

Total $6,000.00

SmartSignal

901 Warrenville Road
Suite 300
Lisle, IL 60532

Invoice

DATE	INVOICE NO.
8/1/2006	1683

BILL TO
Hawaiian Electric Company, Inc. PO Box 2750 Honolulu, HI 96840 Attn: Brenner Munger

P.O. NO.	TERMS	REP
PYA06008010101	Net 30	GW

ITEM	DESCRIPTION	RATE	QTY	AMOUNT
Smart Start D	Live monitoring for the period 7/15/06-8/14/06.	6,000.00		6,000.00

APPROVED FOR PAYMENT
BY: [signature]
DATE 8-9-06
MIMS CONTRACT # PYA06008-01-01-01
Payment Amt.: $6,000.00

Please remit to above address or use wiring instructions--payable in US dollars	**Total**	$6,000.00

SmartSignal
901 Warrenville Road
Suite 300
Lisle, IL 60532

Invoice

DATE	INVOICE NO.
8/30/2006	1698

BILL TO
Hawaiian Electric Company, Inc. PO Box 2750 Honolulu, HI 96840 Attn: Brenner Munger

P.O. NO.	TERMS	REP
PYA06008010101	Net 30	GW

ITEM	DESCRIPTION	RATE	QTY	AMOUNT
Smart Start D	Live monitoring for the period 8/15/06-9/14/06 per the extension executed by Thomas Simmons.	6,000.00		6,000.00

APPROVED FOR PAYMENT
BY: B Munger gn
DATE 9/12/06
MIMS CONTRACT # PYA06008-01-01-01
Payment Amt: $6,000.00

Please remit to above address or use wiring instructions--payable in US dollars	**Total** $6,000.00

SmartSignal
901 Warrenville Road
Suite 300
Lisle, IL 60532

Invoice

DATE	INVOICE NO.
9/26/2006	1719

BILL TO
Hawaiian Electric Company, Inc. PO Box 2750 Honolulu, HI 96840 Attn: Brenner Munger

P.O. NO.	TERMS	REP
PYA06008010101	Net 30	GW

ITEM	DESCRIPTION	RATE	QTY	AMOUNT
Smart Start D	Live monitoring for the period 9/15/06-10/14/06 per the extension executed by Thomas Simmons.	6,000.00		6,000.00

APPROVED FOR PAYMENT
BY: BMunger
DATE 10/11/06
MIMS CONTRACT # PYA-06-008-01-01-01
Payment Amt: $6,000.00

Please remit to above address or use wiring instructions--payable in US dollars	**Total** $6,000.00

SmartSignal

901 Warrenville Road
Suite 300
Lisle, IL 60532

Invoice

DATE	INVOICE NO.
10/30/2006	1748

BILL TO
Hawaiian Electric Company, Inc. PO Box 2750 Honolulu, HI 96840 Attn: Brenner Munger

P.O. NO.	TERMS	REP
PYA06008010101	Net 30	GW

ITEM	DESCRIPTION	RATE	QTY	AMOUNT
Smart Start D	Live monitoring for the period 10/15/06-11/14/06 invoice 3 of 7 per the extension executed by Thomas Simmons.	6,000.00	1	6,000.00

APPROVED FOR PAYMENT
BY: BMunger
DATE 11/14/06
MIMS CONTRACT # PYA-06-008-01-01-01
Payment Amt: $6,000.00

Please remit to above address or use wiring instructions--payable in US dollars

Total $6,000.00

Remit Payments to:	Domestic Wire Transfer	International Wire Transfer
901 Warrenville Rd. Suite 300 Lisle, IL 60532 FEIN# 36-4118627	To: Sil Vly Bk SJ Routing and Transit #:121140399 For Credit of:SmartSignal Corporation Credit Account #:3300168079	Pay to: FC-Silicon Valley Bank 3003 Tasman Drive Santa Clara, CA 95054, USA Routing & Transit #: 121140399 Swift Code: SVBKUS6S For Credit of: SmartSignal Corporation Final Credit Account #: 3300168079

SmartSignal

901 Warrenville Road
Suite 300
Lisle, IL 60532

Invoice

DATE	INVOICE NO.
11/30/2006	1778

BILL TO
Hawaiian Electric Company, Inc. PO Box 2750 Honolulu, HI 96840 Attn: Brenner Munger

P.O. NO.	TERMS	REP
PYA06008010101	Net 30	GW

ITEM	DESCRIPTION	RATE	QTY	AMOUNT
Smart Start D	Live monitoring for the period 11/15/06-12/14/06 invoice 4 of 7 per the extension executed by Thomas Simmons.	6,000.00	1	6,000.00

APPROVED FOR PAYMENT
BY: [signature]
DATE 12/18/06
MIMS CONTRACT # PYA06008.01.01.01
Payment Amt: $6,000.00

Please remit to above address or use wiring instructions--payable in US dollars

Total $6,000.00

Remit Payments to:	Domestic Wire Transfer	International Wire Transfer
901 Warrenville Rd. Suite 300 Lisle, IL 60532 FEIN# 36-4118627	To: Sil Vly Bk SJ Routing and Transit #:121140399 For Credit of:SmartSignal Corporation Credit Account #:3300168079	Pay to: FC-Silicon Valley Bank 3003 Tasman Drive Santa Clara, CA 95054, USA Routing & Transit #: 121140399 Swift Code: SVBKUS6S For Credit of: SmartSignal Corporation Final Credit Account #: 3300168079

SmartSignal

901 Warrenville Road
Suite 300
Lisle, IL 60532

Invoice

DATE	INVOICE NO.
12/22/2006	1824

BILL TO
Hawaiian Electric Company, Inc. PO Box 2750 Honolulu, HI 96840 Attn: Brenner Munger

P.O. NO.	TERMS	REP
PYA06008010101	Net 30	GW

ITEM	DESCRIPTION	RATE	QTY	AMOUNT
Smart Start D	Live monitoring for the period 12/15/06-1/14/07 invoice 5 of 7 per the extension executed by Thomas Simmons.	6,000.00	1	6,000.00

APPROVED FOR PAYMENT
BY: BMunger
DATE 1/25/07
MIMS CONTRACT # PYA06008-01-01-01
Payment Amt: $6,000.00

Please remit to above address or use wiring instructions--payable in US dollars

Total $6,000.00

Remit Payments to:	Domestic Wire Transfer	International Wire Transfer
901 Warrenville Rd. Suite 300 Lisle, IL 60532 FEIN# 36-4118627	To: Sil Vly Bk SJ Routing and Transit #:121140399 For Credit of:SmartSignal Corporation Credit Account #:3300168079	Pay to: FC-Silicon Valley Bank 3003 Tasman Drive Santa Clara, CA 95054, USA Routing & Transit #: 121140399 Swift Code: SVBKUS6S For Credit of: SmartSignal Corporation Final Credit Account #: 3300168079

SmartSignal

901 Warrenville Road
Suite 300
Lisle, IL 60532

Invoice

DATE	INVOICE NO.
1/31/2007	1852

BILL TO
Hawaiian Electric Company, Inc. PO Box 2750 Honolulu, HI 96840 Attn: Brenner Munger

P.O. NO.	TERMS	REP
PYA06008010101	Net 30	GW

ITEM	DESCRIPTION	RATE	QTY	AMOUNT
Smart Start D	Live monitoring for the period 1/15/07-2/14/07 invoice 6 of 7 per the extension executed by Thomas Simmons.	6,000.00	1	6,000.00

APPROVED FOR PAYMENT
BY: B Munger
DATE 2/6/07
MIMS CONTRACT # PYA06008-01-01-01
Payment Amt' $6,000.00

Please remit to above address or use wiring instructions--payable in US dollars	Total $6,000.00

Remit Payments to:	Domestic Wire Transfer	International Wire Transfer
901 Warrenville Rd. Suite 300 Lisle, IL 60532 FEIN# 36-4118627	To: Sil Vly Bk SJ Routing and Transit #:121140399 For Credit of:SmartSignal Corporation Credit Account #:3300168079	Pay to: FC-Silicon Valley Bank 3003 Tasman Drive Santa Clara, CA 95054, USA Routing & Transit #: 121140399 Swift Code: SVBKUS6S For Credit of: SmartSignal Corporation Final Credit Account #: 3300168079

SmartSignal
901 Warrenville Road
Suite 300
Lisle, IL 60532

Invoice

DATE	INVOICE NO.
2/22/2007	1871

BILL TO
Hawaiian Electric Company, Inc. PO Box 2750 Honolulu, HI 96840 Attn: Brenner Munger

P.O. NO.	TERMS	REP
PYA06008010101	Net 30	GW

ITEM	DESCRIPTION	RATE	QTY	AMOUNT
Smart Start D	Live monitoring for the period 2/15/07-2/28/07 invoice 7 of 7 per the extension executed by Thomas Simmons.	3,000.00	1	3,000.00

Amended

APPROVED FOR PAYMENT
BY: Brenner Munger
DATE 3/12/07
MIMS CONTRACT # PYA-06-008.01.01.01
Payment Amt: $3,000.00

Please remit to above address or use wiring instructions--payable in US dollars

Total $3,000.00

Remit Payments to:	Domestic Wire Transfer	International Wire Transfer
901 Warrenville Rd. Suite 300 Lisle, IL 60532 FEIN# 36-4118627	To: Sil Vly Bk SJ Routing and Transit #:121140399 For Credit of:SmartSignal Corporation Credit Account #:3300168079	Pay to: FC-Silicon Valley Bank 3003 Tasman Drive Santa Clara, CA 95054, USA Routing & Transit #: 121140399 Swift Code: SVBKUS6S For Credit of: SmartSignal Corporation Final Credit Account #: 3300168079

DOD-122

Refer to CA-IR-302 pages 6-8 of 8.

a. Please provide the equivalent of page 7 of 8 showing actual employee counts for January through June 2007.
b. Please explain fully and in detail how page 7 of 8 shows 1541 employees for January 2007 when the actual employee count at the end of 2006 was approximately 1445 (per page 8). What comprises the difference between the 1445 Company Total on page 8 for 2006 projected EOY and the 1541 Jan07 total on page 7? Identify, quantify and explain each component of the difference.
c. As of June 30, 2007, please identify by department, the number of vacant positions.
d. As of May 31, 2007, please identify by department, the number of vacant positions.

<u>HECO Response</u>:

a. Please see page 3 of this response for the actual employee counts for January through June 2007.

b. The January 2007 employee count (CA-IR-302, page 7) represents the labor resources needed to complete the required work regardless of the number of employees projected (per CA-IR-302, page 8) to be on payroll at year-end 2006. The level of employees included in the adjusted budget as of January 1, 2007 in direct testimony was 1,541, as shown in HECO-WP-1401. However, as explained in HECO T-14, HECO did not expect to have that number of employees on board as of January 1, 2007, and provided the estimated employee count as of December 31, 2006 (taking into account the DSM adjustment) in HECO-1403. The testimony also explained why the 2006 Projected End-of-Year estimated employee counts was <u>not</u> used as a surrogate for the January 1, 2007 employee count estimate in the calculation to determine the Company's average test year employee count.

The 2006 Projected End-of-Year estimate is used for internal work planning and is continually updated as information on retirements, transfers and new positions becomes known. As explained by the Operations and Maintenance ("O&M") witnesses, HECO requires the additional employees in the O&M budget to perform the work that the Company expects to complete in 2007. By reflecting the resource requirements as regular employees, the Company also has forecasted the associated labor costs that are required to perform such work. (See HECO T-14, pages 3-4.)

Adjusting the test year O&M expenses to reflect the fact that a significant number of positions would not be filled at the beginning of 2007 would result in a significant understatement of the O&M expenses expected for 2007, unless upward revisions also were made to reflect the additional overtime, contract services and temporary hires that would have to be incurred or added to accomplish the expected work load. Thus, the actual 2006 year-end work force level has no relationship to the 2007 test year budget, and it would be inappropriate to include it in the calculation of the average employees in the test year. (See HECO T-14, pages 5-7.)

In each O&M area, witnesses were asked to make an adjustment to their test year O&M expenses <u>if</u> the work to be done by the additional employees was expected to be deferred beyond 2007, but <u>not</u> if the work was expected to be accomplished through other means that would result in the incurrence of O&M expenses, or if the additional employees were expected to be hired shortly after the beginning of 2007. The individual witnesses addressed the estimated number of positions required by their departments, and explained why adjustments were made or not made. Additional information has been provided by the witnesses in their IR responses.

c. Please refer to the Company's response to CA-IR-465, pages 2 through 5.

d. Please see pages 4 through 7 of this response.

Dept	Jan-07	Feb-07	Mar-07	Apr-07	May-07*	Jun-07**
Comp & Ben	13	13	13	13	14	14
Ind Rel	9	9	9	9	8	8
SSF	41	41	41	42	42	42
VP-Corp Exc	2	2	2	2	2	2
WFSD	17	15	16	17	17	16
	82	**80**	**81**	**83**	**83**	**82**
Corp Comm	8	6	8	8	8	8
VP-Corp Rel	3	3	3	3	3	3
	11	**9**	**11**	**11**	**11**	**11**
CustTechAp	8	8	8	9	9	8
Engy Svcs	18	17	17	17	18	18
Fcst&Res	10	10	10	10	10	10
IRP	6	6	0	0	0	0
Mktg Svcs	12	12	12	12	12	11
VP-Cust Sol	2	2	2	2	2	2
	56	**55**	**49**	**50**	**51**	**49**
C&M	217	217	218	217	214	214
Engineering	83	85	84	85	87	89
Supp Svcs	81	81	81	81	82	82
Sys Op	107	108	108	108	108	109
VP-En Del	2	2	2	2	2	2
	490	**493**	**493**	**493**	**493**	**496**
CID	44	45	44	44	44	44
Engy Proj	8	8	9	9	9	9
SVP-EnSol	4	4	4	4	4	4
Tech	3	3	3	3	3	3
	59	**60**	**60**	**60**	**60**	**60**
Financial VP	4	4	4	4	4	4
Gen Acctg	26	25	23	25	25	25
InfoTech	96	94	91	91	91	91
MAFS	22	22	22	22	20	20
RiskMgt	9	9	9	9	9	9
	157	**154**	**149**	**151**	**149**	**149**
Legal	16	16	17	17	17	17
VPGen	2	2	2	2	2	2
	18	**18**	**19**	**19**	**19**	**19**
Ed & Cons Aff	8	7	6	6	6	6
Reg Affairs	8	8	8	8	10	10
VP-Gov & Com	7	7	7	7	7	8
	23	**22**	**21**	**21**	**23**	**24**
Cust Svc	128	125	128	129	131	135
SVP-Oper	2	2	2	2	2	2
	130	**127**	**130**	**131**	**133**	**137**
CorpAudComp	9	9	11	10	10	10
President	2	2	2	3	3	3
	11	**11**	**13**	**13**	**13**	**13**
Gov Rel	3	3	3	3	2	2
IRP	0	0	6	6	5	5
SVP-Pub Aff	3	3	3	3	3	3
	6	**6**	**12**	**12**	**10**	**10**
Environ	22	21	22	22	22	20
Production	341	351	348	351	354	357
PwrSup Eng	41	41	42	42	42	42
VP-Pwr Sup	2	2	2	2	2	2
	406	**415**	**414**	**417**	**420**	**421**
Company Total	**1449**	**1450**	**1452**	**1461**	**1465**	**1471**

*Excludes 13 Summer Interns from various Departments.
**Excludes 20 Summer Interns from various Departments.

Hawaiian Electric Company Inc.
Actual Employee Count vs. 2007 EOY Test Year Employee Count
as of May 31, 2007

			ACTUAL EMPLOYEE COUNT										
			A	B	C	D	E	F	G	H	I	J	K
DEPARTMENT	DIVISION	RA	FULL TIME	PART TIME	TEMP†	TOTAL	UPDATED 2007 EOY TEST YEAR	MGMT TSFS	MANAGEMENT TRANSFERS[1]	UPD 2007 EOY TEST YEAR (E + F)	DIFF (D - H)	JVR RECEIVED	JVR NOT YET RECEIVED
COMPENSATION AND BENEFITS	EMPL BENEFITS & HLTH SVCS	PFB	8	0	0	8	10			10	(2)	Employee Benefits Administrator (Filled start 7/16/07)	
												Administrative Assistant	
COMPENSATION AND BENEFITS	COMPENSATION	PFC	2	0	0	2	2			2			
COMPENSATION AND BENEFITS	DISABILITY MANAGEMENT	PPW	4	0	0	4	3			3	1	Director, Disability Management retired 7/3/07. Replacement started 5/28/07.	
INDUSTRIAL RELATIONS	ADMINISTRATION	PPA	3	0	0	3	3			3			
INDUSTRIAL RELATIONS	LABOR REL & WAGE ADMIN	PPI	5	0	0	5	6			6	(1)		Consultant
SAFETY, SECURITY & FACILITIES	CORPORATE SAFETY	PFS	11	0	0	11	12			12	(1)	OCC Health & Safety Specialist (Filled start 7/2/07)	
SAFETY, SECURITY & FACILITIES	ADMINISTRATION	PHA	2	0	0	2	2			2			
SAFETY, SECURITY & FACILITIES	FACILITIES OPERATIONS	PHB	14	0	0	14	15			15	(1)		Custodian
SAFETY, SECURITY & FACILITIES	FACILITIES PLANNING	PHF	8	0	0	8	8			8			
SAFETY, SECURITY & FACILITIES	SECURITY	PHS	7	0	0	7	10			10	(3)		Security Coordinator
													Security Coordinator
													Security Officer
VP CORPORATE EXCELLENCE	VP CORPORATE EXCELLENCE	P6V	2	0	0	2	2			2			
WORKFORCE STAFFING & DEVELOP	ADMINISTRATION	PFA	4	0	0	4	4			4			
WORKFORCE STAFFING & DEVELOP	CLIENT SERVICES & CONSULTING	PFD	10	0	0	10	10			10			
WORKFORCE STAFFING & DEVELOP	ORGANIZ DEV & CONTIN IMPRVMT	PFI	3	0	0	3	3			3			
	CORPORATE EXCELLECE SUBTOTAL		**83**	**0**	**0**	**83**	**90**			**90**	**(7)**		
CORPORATE COMMUNICATIONS	CORPORATE COMMUNICATIONS	PQC	7	1	0	8	9			9	(1)	Director, Corporate Communications	
VP CORPORATE RELATIONS	VP CORPORATE RELATIONS	P1V	3	0	0	3	3			3			
	CORPORATE RELATIONS SUBTOTAL		**10**	**1**	**0**	**11**	**12**			**12**	**(1)**		
CUSTOMER TECH APPLICATIONS	CUSTOMER TECH APPLICATIONS	PSR	9	0	0	9	10			10	(1)	Sr. Technical Services Engineer	
ENERGY SERVICES	ADMINISTRATION	PSA	3	0	0	3	3			3			
ENERGY SERVICES	CUSTOMER EFFICIENCY PROGRAM	PSD**	11	0	0	11	11			11			
ENERGY SERVICES	PRICING	PSP	4	0	0	4	5			5	(1)	Rate Analyst	
FORECASTS & RESEARCH	FORECASTS & RESEARCH	PSM**	10	0	0	10	10			10			
MARKETING SERVICES	MARKETING SERVICES	PSN	12	0	0	12	12			12			
VP CUSTOMER SOLUTIONS	CUSTOMER SOLUTIONS	P1W	2	0	0	2	2			2			
	CUSTOMER SOLUTIONS SUBTOTAL		**51**	**0**	**0**	**51**	**53**			**53**	**(2)**		
CONSTRUCTION & MAINTENANCE	ADMINISTRATION	PDA	5	0	0	5	6			6	(1)		Training Administrator
CONSTRUCTION & MAINTENANCE	CONTROL SECTION	PDC	5	0	0	5	8	(2)	Move 2 positions to PDP	6	(1)		Clerk Typist III
CONSTRUCTION & MAINTENANCE	FIELD OPERATION	PDF	22	0	0	22	22	1	Move 1 position from PDS	23	(1)	Supervisor	
CONSTRUCTION & MAINTENANCE	TRAINING SECTION	PDD*	8	0	0	8							
CONSTRUCTION & MAINTENANCE	WEST OVERHEAD	PDJ*	43	0	0	43							
CONSTRUCTION & MAINTENANCE	EAST OVERHEAD-KOOLAU	PDK*	27	0	0	27							
CONSTRUCTION & MAINTENANCE	EAST OVERHEAD-WARD	PDL*	40	0	0	40							
CONSTRUCTION & MAINTENANCE	UNDERGROUND	PDU*	27	0	0	27							
CONSTRUCTION & MAINTENANCE	OPERATIONS	PDS*	12	0	0	12	170	(10)	Move 8 positions to PDP	160	(3)		Sr. Helper
									Move 1 position to PDV				Sr. Helper
									Move 1 position to PDF				Sr. Helper
CONSTRUCTION & MAINTENANCE	PLANNING	PDP	23	0	0	23	13	10	Move 8 positions from PDS	23			
									Move 2 positions from PDC				
CONSTRUCTION & MAINTENANCE	VEGETATION MANAGEMENT	PDV	2	0	0	2	1	1	Move 1 position from PDS	2			
ENGINEERING	ADMINISTRATION	PBA	7	0	0	7	7			7			
ENGINEERING	T&D ENGINEERING	PBE	22	0	1	23	23			23			
ENGINEERING	PROJECT MANAGEMENT	PBP	7	0	0	7	7			7			
ENGINEERING	STRUCTURAL	PBT	18	0	0	18	18			18			
ENGINEERING	SUBST,PROTECTION&TELECOM	PBY	23	0	1	24	22			22	2	Lead Engineer retiring 8/1/07. Replacement started 3/5/07.	
												Temporarily filled by HECO temp until June 2007	
ENGINEERING	T&D TECHNICAL SERVICES	PBZ	8	0	0	8	8			8			
SUPPORT SERVICES	ADMINISTRATION	PVA	5	0	0	5	5			5			
SUPPORT SERVICES	FLEET	PVF	23	0	0	23	25			25	(2)	Mechanic Helper	
												Automotive Mechanic	
SUPPORT SERVICES	ELECTRICAL & WELDING SERVICES	PVL	12	0	0	12	12			12			
SUPPORT SERVICES	MATERIALS MANAGEMENT	PVM	27	0	0	27	28			28	(1)	Director, Materials Management (Returning August 2007)	
SUPPORT SERVICES	PURCHASING	PVP	15	0	0	15	15			15			
SYSTEM OPERATION	ADMINISTRATION	PRA	7	0	0	7	7			7			
SYSTEM OPERATION	COMMUNICATIONS	PRC	8	0	0	8	8			8			

Hawaiian Electric Company Inc.
Actual Employee Count vs. 2007 EOY Test Year Employee Count
as of May 31, 2007

			ACTUAL EMPLOYEE COUNT										
			A	B	C	D	E	F	G	H	I	J	K
DEPARTMENT	DIVISION	RA	FULL TIME	PART TIME	TEMP†	TOTAL	UPDATED 2007 EOY TEST YEAR	MGMT TSFS	MANAGEMENT TRANSFERS[1]	UPD 2007 EOY TEST YEAR (E + F)	DIFF (D - H)	JVR RECEIVED	JVR NOT YET RECEIVED
SYSTEM OPERATION	OPERATING DISPATCH	PRD	22	0	0	22	27			27	(5)	Trouble Dispatcher	
												Technical Trainer	
												Chief Dispatcher	
												Switching Coordinator	
												Operating Engineer (Offered & Accepted)	
SYSTEM OPERATION	OPERATING ENGINEERING	PRE	11	0	0	11	14			14	(3)	EFMS Technician	
												EFMS Technician	
												System Analyst	
SYSTEM OPERATION	INSTRUMENT & CONTROL	PRI	9	0	0	9	9			9			
SYSTEM OPERATION	RELAY	PRR	10	0	0	10	10			10			
SYSTEM OPERATION	SUBSTATION	PRS	38	0	0	38	39			39	(1)	Substation Operations Specialist	
SYSTEM OPERATION	CONSTRUCTION MANAGEMENT	PRX	3	0	0	3	3			3			
VP ENERGY DELIVERY	VP ENERGY DELIVERY	P2V	2	0	0	2	2			2			
	ENERGY DELIVERY SUBTOTAL		**491**	**0**	**2**	**493**	**509**			**509**	**(16)**		
FINANCIAL VICE PRESIDENT	FINANCIAL VICE PRESIDENT	P4V	4	0	0	4	4			4			
GENERAL ACCOUNTING	ADMINISTRATION	PAA	5	0	0	5	6			6	(1)	Financial Systems Analyst (Filled start 6/11/07)	
GENERAL ACCOUNTING	CORPORATE ACCOUNTING	PAC	5	0	0	5	5			5			
GENERAL ACCOUNTING	COST ACCOUNTING	PAD	10	0	0	10	10			10			
GENERAL ACCOUNTING	PROPERTY ACCOUNTING	PAT	5	0	0	5	5			5			
INFO TECHNOLOGY & SVCS	ADMINISTRATION	PEA	2	0	0	2	2			2			
INFO TECHNOLOGY & SVCS	CUSTOMER CARE	PEC	25	0	0	25	23	2	Move 2 positions from PEI	25			
INFO TECHNOLOGY & SVCS	DEVELOPMENT SERVICES	PED	35	0	0	35	37			37	(2)		Development Analyst
													Development Specialist
INFO TECHNOLOGY & SVCS	INFRASTRUCTURE & OPERATIONS	PEI	22	0	0	22	24	(2)	Move 2 positions to PEC	22			
INFO TECHNOLOGY & SVCS	MAILING SERVICES	PEM	7	0	0	7	8			8	(1)	Mailing Services Coordinator	
MANAGEMENT ACCTG & FIN SVCS	ADMINISTRATION	PKB	4	0	0	4	4			4			
MANAGEMENT ACCTG & FIN SVCS	BUDGETS	PKC	7	0	0	7	7			7			
MANAGEMENT ACCTG & FIN SVCS	FINANCIAL ANALYSIS	PKF	3	0	0	3	3			3			
MANAGEMENT ACCTG & FIN SVCS	ERP ADMINISTRATION	PKM	3	0	0	3	3			3			
MANAGEMENT ACCTG & FIN SVCS	TREASURY	PKT	3	0	0	3	5			5	(2)	Treasury Associate	
												Treasury Analyst	
RISK MANAGEMENT	RISK MANAGEMENT	PKI	9	0	0	9	9			9			
	FINANCE SUBTOTAL		**149**	**0**	**0**	**149**	**155**			**155**	**(6)**		
LEGAL	LEGAL	PNC	12	0	0	12	11			11	1	Overstaff approved - Associate General Counsel filled 3/5/07	
LEGAL	*LAND & RIGHTS OF WAY*	*PNL*	*5*	*0*	*0*	*5*	5			5			
VP GENERAL COUNSEL	VP-GENERAL COUNSEL	P5V	2	0	0	2	2			2			
	GENERAL COUNSEL SUBTOTAL		**19**	**0**	**0**	**19**	**18**			**18**	**1**		
EDUCATION & CONSUMER AFFAIRS	EDUCATION & CONSUMER AFFAIRS	PQE	6	0	0	6	8			8	(2)	Education & Consumer Affairs Administrator	
												Clerk Typist III	
REGULATORY AFFAIRS	REGULATORY AFFAIRS	PNP	10	0	0	10	15			15	(5)	Regulatory Analyst II	Manager, Regulatory Affairs
												Regulatory Analyst II	Director Position (Title to be developed)
													Legal Assistant
VP GOVT & COMMUNITY AFFAIRS	VP GOVT & COMMUNITY AFFAIRS	P3V	7	0	0	7	7			7			
	GOVT & COMMUNITY AFFAIRS SUBTOTAL		**23**	**0**	**0**	**23**	**30**			**30**	**(7)**		
ENVIRONMENTAL	ADMINISTRATION	PJA	4	0	0	4	4			4			
ENVIRONMENTAL	AIR QUALITY & NOISE	PJB	5	0	0	5	6			6	(1)	Sr. Environmental Scientist	
ENVIRONMENTAL	CHEMISTRY	PJC	6	0	0	6	6			6			
ENVIRONMENTAL	WATER & HAZARDOUS MATERIAL	PJW	7	0	0	7	8			8	(1)		Environmental Scientist
POWER SUPPLY ENGINEERING	ADMINISTRATION	PYA	3	0	0	3	3			3			
POWER SUPPLY ENGINEERING	SUPPORT STAFF	PYC	2	0	0	2	2			2			
POWER SUPPLY ENGINEERING	PS TECHNICAL SERVICES	PYE	8	0	0	8	9			9	(1)	Sr. Staff Engineer - Controls	
POWER SUPPLY ENGINEERING	POWER PLANT ELECT ENGRG	PYF	10	0	0	10	12	(1)	Move 1 position to PYM	11	(1)	Engineer II - Electrical	
POWER SUPPLY ENGINEERING	POWER PLANT DRAFTING	PYG	2	0	0	2	2			2			
POWER SUPPLY ENGINEERING	POWER PLANT PROJECT MGT	PYJ	4	0	0	4	5	(1)	Move 1 position to PYM	4			
POWER SUPPLY ENGINEERING	POWR PLANT MECH ENGRG	PYM	13	0	0	13	12	2	Move 1 position from PYJ	14	(1)	Engineer II - Mechanical	
									Move 1 position from PYF				
POWER SUPPLY OPER & MAINT	O&M ADMINISTRATION	PIB[2]	8	0	0	8	9			9	(1)		Administrator
POWER SUPPLY OPER & MAINT	TRAINING	PID	2	0	0	2	3			3	(1)		Technical Trainer
POWER SUPPLY OPER & MAINT	HONOLULU STATION OPERATIONS	PIH	25	0	0	25	27			27	(2)	Operator Trainee	
												Shift Supervisor	
POWER SUPPLY OPER & MAINT	KAHE STATION OPERATIONS	PIK	60	0	0	60	61			61	(1)	Operator Trainee	
POWER SUPPLY OPER & MAINT	KAHE STATION MAINTENANCE	PIL	28	0	0	28	33			33	(5)	Pipefitter Mechanic	
												Pipefitter Mechanic	

Hawaiian Electric Company Inc.
Actual Employee Count vs. 2007 EOY Test Year Employee Count
as of May 31, 2007

			ACTUAL EMPLOYEE COUNT										
			A	B	C	D	E	F	G	H	I	J	K
DEPARTMENT	DIVISION	RA	FULL TIME	PART TIME	TEMP†	TOTAL	UPDATED 2007 EOY TEST YEAR	MGMT TSFS	MANAGEMENT TRANSFERS[1]	UPD 2007 EOY TEST YEAR (E + F)	DIFF (D - H)	JVR RECEIVED	JVR NOT YET RECEIVED
												Welder (Offered & Accepted)	
												Control Technician	
												Control Technician	
POWER SUPPLY OPER & MAINT	MAINTENANCE ADMINISTRATION	PIM	2	0	0	2	3			3	(1)		Rotating Equipment Specialist
POWER SUPPLY OPER & MAINT	HONOLULU STATION MAINTENANCE	PIN	10	0	0	10	12	(1)	Move 1 position to PIP	11	(1)	Welder (Offered & Accepted)	
POWER SUPPLY OPER & MAINT	OPERATIONS ADMINISTRATION	PIO	2	0	0	2	2			2			
POWER SUPPLY OPER & MAINT	PLANNING AND ENGINEERING	PIP	22	0	0	22	24	1	Move 1 position from PIN	25	(3)	Resource Planner	Predictive Maintenance Specialist
												Predictive Maintenance Specialist	
POWER SUPPLY OPER & MAINT	TRAVELING MAINTENANCE	PIT	71	0	0	71	81			81	(10)	Pipefitter Mechanic	
												Pipefitter Mechanic	
												Control Technician	
												Welder	
												Welder	
												Condenser Cleaner (Filled, start 6/4/07)	
												Insulator	
												Insulator	
												Machinist	
												Mobile Crane & Equip Operator (Filled start 7/23/07)	
POWER SUPPLY OPER & MAINT	WAIAU STATION OPERATIONS	PIW	64	0	0	64	66			66	(2)	Operator Trainee	Operator Trainee
POWER SUPPLY OPER & MAINT	WAIAU STATION MAINTENANCE	PIX	30	0	0	30	32			32	(2)	Control Technician	Maintenance Helper
POWER SUPPLY SERVICES	SERVICES ADMINISTRATION	PIA	3	0	0	3	3			3			
POWER SUPPLY SERVICES	POWER PURCHASE	PIC	6	0	0	6	6			6			
POWER SUPPLY SERVICES	FUEL RESOURCES	PIF	2	0	0	2	4			4	(2)	Fuels Contract Administrator	
												Fuels Contract Administrator	
POWER SUPPLY SERVICES	FUEL INFRASTRUCTURE	PIJ[2]	1	0	0	1	3			3	(2)	Staff Engineer	
												Staff Engineer	
SYSTEM PLANNING	ADMINISTRATION	PXA	2	0	0	2	2			2			
SYSTEM PLANNING	GENERATION BIDDING	PXB[2]	0	0	0	0	3			3	(3)	Director, Generation Bidding (Filled start 6/11/07)	Project Manager
													Project Manager
SYSTEM PLANNING	GENERATION PLANNING	PYB	9	0	0	9	9			9			
SYSTEM PLANNING	TRANSMISSION PLANNING	PYT	8	0	0	8	8			8			
VP POWER SUPPLY	VP POWER SUPPLY	P7V	2	0	0	2	2			2			
	POWER SUPPLY SUBTOTAL		***421***	***0***	***0***	***421***	***462***			***462***	***(41)***		
CORPORATE AUDIT & COMPLIANCE	INTERNAL AUDIT	PNA	7	0	0	7	8			8	(1)		Internal Auditor
CORPORATE AUDIT & COMPLIANCE	ADMINISTRATION	PNX	3	0	0	3	4			4	(1)		Secretary
PRESIDENTS OFFICE	PRESIDENTS OFFICE	P9P	3	0	0	3	3			3			
	PRESIDENT - HECO SUBTOTAL		**13**	**0**	**0**	**13**	**15**			**15**	**(2)**		
CUSTOMER INSTALLATION	ADMINISTRATION	PWA	12	0	0	12	12			12			
CUSTOMER INSTALLATION	PLANNING & DESIGN	PWP	21	0	0	21	27			27	(6)	Jr. Drafter	Jr. Drafter
													Jr. Customer Planner
													Jr. Customer Planner
													Jr. Customer Planner
													Customer Engineer
CUSTOMER INSTALLATION	ENGINEERING & METER	PWX	11	0	0	11	14			14	(3)	Supervisor, Meter (Offered & Accepted)	Meter Engineer
												Director, Advanced Meter Infrastructure	
ENERGY PROJECTS	ENERGY PROJECTS	PNG	9	0	0	9	9			9			
SR VP ENERGY SOLUTIONS	SR VP ENERGY SOLUTIONS	P9S	4	0	0	4	4			4			
TECHNOLOGY	TECHNOLOGY	PNR	2	0	1	3	3			3			
	SR VP ENERGY SOLUTIONS SUBTOTAL		**59**	**0**	**1**	**60**	**69**			**69**	**(9)**		
CUSTOMER SERVICE	ADMINISTRATION	PCA***	4	0	0	4	5			5	(1)		Operations Analyst
CUSTOMER SERVICE	CUST ACCOUNTING & BILLING	PCB	6	0	0	6	6			6			
CUSTOMER SERVICE	CREDIT	PCD	5	0	0	5	5			5			
CUSTOMER SERVICE	CUSTOMER FIELD SERVICES	PCF***	4	0	1	5	5			5			
CUSTOMER SERVICE	FIELD SERVICE & COLLECTIONS	PCG***	26	0	0	26	26			26			
CUSTOMER SERVICE	CUSTOMER ASSISTANCE CENTER	PCH	31	0	0	31	30			30	1	Temporarily overstaffed due to CIS Project	
CUSTOMER SERVICE	METER READING	PCM	33	0	0	33	34			34	(1)	Meter Reader	
CUSTOMER SERVICE	PAYMT PROCESS & SUPPORT CTR	PCP	16	0	0	16	17			17	(1)	Account Services Clerk	
CUSTOMER SERVICE	CUSTOMER ACCOUNT SERVICES	PCS	5	0	0	5	5			5			
SR VP OPERATIONS	SR VP OPERATIONS	P8V	2	0	0	2	2			2			
	SR VP OPERATIONS SUBTOTAL		**132**	**0**	**1**	**133**	**135**			**135**	**(2)**		

Hawaiian Electric Company Inc.
Actual Employee Count vs. 2007 EOY Test Year Employee Count
as of May 31, 2007

			ACTUAL EMPLOYEE COUNT										
			A	B	C	D	E	F	G	H	I	J	K
DEPARTMENT	DIVISION	RA	FULL TIME	PART TIME	TEMP†	TOTAL	UPDATED 2007 EOY TEST YEAR	MGMT TSFS	MANAGEMENT TRANSFERS[1]	UPD 2007 EOY TEST YEAR (E + F)	DIFF (D - H)	JVR RECEIVED	JVR NOT YET RECEIVED
GOVERNMENTAL RELATIONS	GOVERNMENTAL RELATIONS	PNI	2	0	0	2	3			3	(1)		Director, Government Relations
INTEGRATED RESOURCE PLNG	INTEGRATED RESOURCE PLANNING	PYP	5	0	0	5	6			6	(1)	Sr. Resource Planning Analyst	
SR VP PUBLIC AFFAIRS	SR VP PUBLIC AFFAIRS	P9V	3	0	0	3	3			3			
	SR VP PUBLIC AFFAIRS SUBTOTAL		**10**	**0**	**0**	**10**	**12**			**12**	**(2)**		
	COMPANY TOTAL		**1461**	**1**	**4**	**1466**	**1560**			**1560**	**(94)**		

N.1. Reflects current organizational structure as of 6/30/07.
N.2. Column D excludes 13 summer interns working in various departments.
N.3. See F.Chiogioji (T-14) June 2007 Update (revised 6/29/07) for Company Totals (columns E and H).

DOD-IR-123

Refer to CA-IR-305 page 2 and 3 of 5.

a. Has the correction for the portion of the regulatory asset for AFUDC Equity Gross up (CWIP Equity Ongoing) been reflected in HECO's June 2007 update? If so, where is this reflected.

b. If not reflected in the June 2007 update, please identify the amount of correction needed, and include supporting calculations.

HECO Response:

a. Yes. See June 2007 Update, HECO T-15, pages 5 and 7. Note that the AFUDC Equity Gross up will be updated due to a change in AFUDC.

b. The correction referenced in part a. above has been updated from the June 2007 update filing. See pages 2 and 3 of this response for the revised schedule. HECO will be updating HECO T-15 June 2007 Update filed on June 29, 2007 to reflect this change.

REVISED HECO-1506
(UPDATED: 7/23/07)

HAWAIIAN ELECTRIC COMPANY, INC.
SFAS 109 RECONCILIATION
REGULATORY ASSETS AND LIABILITIES

($ Thousand)

		H Actual Balance 12/31/2005	I Actual 2006 Amort	J Actual 2006 Adds	K Actual Balance 12/31/2006	L Updated 2007 Amort	M Updated 2007 Adds	N Updated Balance 12/31/2007
1	CWIP Equity Transition (#18673100)	1,850	(85)		1,765	(75)		1,690
2	SFAS 109 Flow Through (#18673200)	3,264	(326)		2,938	(326)		2,612
3	Plant Transition (#18673300)	20,459	(1,023)		19,436	(1,023)		18,413
4	AFUDC Equity Gross up (#18673400)	30,280	(893)	2,585	31,972	(935)	3,508	34,545
*5	Adjustment for AFUDC Equity Gross up in CWIP	(4,171)		117	(4,054)		(511)	(4,565)
6	Federal ITC (#18673500)	(3,011)	539		(2,472)	487		(1,985)
	Excess Deferred Taxes							
7	(#18673110 - Acct 282)	(1,809)	904		(905)	904		(1)
8	(#18673900 - Acct 283)	(1,414)	58		(1,356)	58		(1,298)
9	Subtotal	(3,223)	962	-	(2,261)	962	-	(1,299)
	Deficit Deferred Taxes							
10	(#18673120 - Acct 282)	2,216	(111)		2,105	(111)		1,994
11	(#18673190 - Acct 283)	-	-		-	-		-
12	Subtotal	2,216	(111)	-	2,105	(111)	-	1,994
13	TOTAL	47,664	(937)	2,702	49,429	(1,021)	2,997	51,405
13	AVERAGE BALANCE				48,547			50,417

* Line 5 represents the adjustments to exclude the AFUDC equity gross up still in CWIP.

NOTE: All SFAS 109 assets and liabilities and related taxes have been computed on effective tax rate of 32.8947368% (federal) and 6.0150376% (state).

HAWAIIAN ELECTRIC CO., INC.
REGULATORY ASSET - AFUDC EQUITY GROSS UP (#18673400)

		Actual 2002	Actual 2003	Actual 2004	Actual 2005	Actual 2006	Update 2007
ORIGINAL							
Beginning Balance		22,774	24,372	25,994	28,552	30,279	31,971
Equity Gross up addition		2,238	2,326	3,328	2,567	2,585	3,508
Amortization		(640)	(704)	(770)	(840)	(893)	(935)
Ending Balance		24,372	25,994	28,552	30,279	31,971	34,544
Average			25,183	27,273	29,416	31,125	33,258
REVISED							
Beginning Balance		22,774	22,694	23,131	24,334	26,108	27,917
Equity Gross up addition		2,238	2,326	3,328	2,567	2,585	3,508
Adjustment							
Add 25% of Current Year	25%	560	582	832	642	646	877
Add 25% of Prior Year 1	25%		560	582	832	642	646
Add 25% of Prior Year 2	25%			560	582	832	642
Add 25% of Prior Year 3	25%				560	582	832
Deduct Current Year	100%	(2,238)	(2,326)	(3,328)	(2,567)	(2,585)	(3,508)
Total Adjustment		(1,679)	(1,185)	(1,355)	48	117	(511)
Amortization		(640)	(704)	(770)	(840)	(893)	(935)
Ending Balance		22,694	23,131	24,334	26,108	27,917	29,979
Difference		1,679	2,864	4,219	4,171	4,054	4,565
Deferred Tax Effect of Reg Asset: AFUDC Equity Gross up Adjustment							
Federal	32.8947%	552	942	1,388	1,372	1,334	1,502
State	6.0150%	101	172	254	251	244	275
Total		653	1,114	1,641	1,623	1,577	1,776

NOTE: This worksheet calculates the amounts of AFUDC Equity Gross up still in CWIP, and the related deferred tax effects.

DOD-IR-124

<u>Ref: Refer to CA-IR-307, attachment 4, page 3 of 4.</u>

a. Please explain the 102% "Economy Factor" that HECO applied to the six year average of Customer Advances.

b. For the "2007 receipts – estimate" why did HECO use $125,000 or $127,000 as opposed to $120,000? Explain fully.

c. Show in detail how the 90% "Transfer to CIAC Factor" was calculated.

HECO Response:

a. The "Economy Factor" is intended to adjust historical costs for inflation. Based on the assumption that costs of construction were increasing due to inflation, HECO assumed that Customer Advances would increase at the same rate. The 2% was chosen as the Economy Factor since 2% was used by HECO to develop its Customer Advances estimate in its 2005 Test Year Rate Case, Docket No. 04-0113. The Consumer Price Index (CPI) estimate for 2007 from the "Blue Chip Economic Indicator", published May 10, 2007, is 2.5%. Thus, it appears that the 2% Economy Factor is a reasonable and conservative estimate for inflation that may occur in 2007.

b. The "2007 receipts estimate" of $120,000 was used rather than $125,000 or $127,000 because the 2001 through 2006 historical recorded Customer Advance receipts were showing a downward trend (see the referenced attachment). Based on this downward trend HECO "rounded down" the 2007 receipts estimate to $120,000.

c. There is no detailed calculation for the 90% "Transfer to CIAC Factor". The 90% factor was used to recognize that Customer Advances in the 10-year-old category are also subject to refund, i.e., 100% of the advance may not be transferred.

DOD-IR-125

Ref: EEI.

Please break out the amount of Edison Electric Institute (EEI) dues in the 2007 test year into the following:

a. Core dues
b. Utility Solid Waste Activities Group (USWAG) membership dues
c. Industry Structure Separately Funded Activities dues
d. Environmental Structure Separately Funded Activities dues

HECO Response:

a. The estimated 2007 test year EEI membership dues are allocated to the following categories according to the EEI membership dues invoice:

2007 Membership Dues For:	2007 EEI Membership	Simplification Adjustment	2007 Test Year
Regular Activities of Edison Electric Institute	244,580	(61,145)	183,435
Industry Structure Assessment	36,687	(25,681)	11,006
Mutual Assistance Program	3,342	—	3,342
Total 2007 EEI Dues	284,609	(86,826)	197,783

b. The EEI invoice does not break out “Utility Solid Waste Activities Group (USWAG)” membership dues.

c. The EEI invoice does not break out “Industry Structure Separately Funded Activities” dues. However, the invoice does have an “Industry Structure Assessment” category. See response to item a above.

d. The EEI invoice does not break out “Environmental Structure Separately Funded Activities” dues.

DOD-IR-126

Ref: EEI.

Please break out the amount of actual 2006 EEI dues into the following:

a. Core dues
b. Utility Solid Waste Activities Group (USWAG) membership dues
c. Industry Structure Separately Funded Activities dues
d. Environment Structure Separately Funded Activities dues

HECO Response:

a. As discussed in HECO T-13, page 18, although HECO was a member of EEI in 2006, EEI waived its 2006 membership fees for HECO. Therefore, HECO did not pay any 2006 EEI dues.
b. See response to item a. above.
c. See response to item a. above.
d. See response to item a. above.

DOD-IR-127

Ref: EEI.

a. Please provide EEI invoices for 2006 and 2007.

b. Please show all amounts recorded by HECO for EEI in 2006 and 2007 by account and type of EEI dues. This would include all EEI dues that HECO recorded in operating expense accounts and below-the-line lobbying expense accounts (e.g., Account 426).

c. Please show in detail how HECO determined the amount of EEI dues to be recorded to below-the-line accounts for 2006 and 2007 actual, and for its estimated 2007 test year EEI expense.

d. Please provide all communications from EEI in 2006 and 2007 relating to identification of the portions of EEI dues relating to influencing legislation and EEI dues-funded activities that are considered "non-deductible" for federal income tax purposes.

e. Please provide breakouts of EEI dues for each year 2005, 2006 and 2007 into the NARUC specified operating expense categories: (1) legislative advocacy, (2) legislative policy research, (3) regulatory advocacy, (4) regulatory policy research, (5) advertising, (6) marketing, (7) utility operations and engineering, (8) finance, legal, planning and customer service, and (9) public relations.

HECO Response:

a. See Attachment 1 for copies of the 2007 quarterly EEI membership invoices. See HECO-1304, page 6 for the Company's 2006 EEI membership invoice copy. HECO did not pay this invoice in 2006 as its membership fees were waived by EEI (see response to item b. below for further detail).

b. As mentioned in the Company's response to part a. of DOD-IR-126, although HECO was a member of EEI in 2006, EEI waived its 2006 membership fees for HECO. Therefore, HECO did not pay any 2006 EEI dues. In 2007, HECO has recorded its allocated portion of approximately $148,000 of EEI membership dues (1st and 2nd quarter dues) to NARUC Account 9302, "Miscellaneous General Expenses." The remaining amounts have been allocated to MECO and HELCO.

c. HECO does not record its EEI membership costs to any below-the-line NARUC account, rather it records all of the costs of its EEI membership dues to NARUC Account 9302, "Miscellaneous General Expenses." However, as mentioned in B. Tamashiro's direct testimony (T-13), on page 16, for rate case purposes, a simplification adjustment is made to exclude the portion of the Company's EEI dues related to government lobbying. Accordingly, an adjustment is made to exclude the EEI dues related to government lobbying from the Company's monthly calculation of its rate of return amounts which are filed with the PUC. Refer to HECO-1304, page 5, for the calculation of EEI dues related to government lobbying.

d. There have been no communications with EEI in 2006 and 2007 relating to influencing legislation and EEI dues-funded activities that are considered "non-deductible" for federal income tax purposes.

e. As mentioned in HECO's response to part c. above, HECO records all of the costs of its EEI membership dues to NARUC Account 9302, "Miscellaneous General Expenses."

EEI EDISON ELECTRIC INSTITUTE

INVOICE FOR MEMBERSHIP DUES

701 PENNSYLVANIA AVENUE, NW
WASHINGTON, DC 20004-2696
PHONE (202) 508-5000

Date	Invoice Number
03/26/2007	1-000050682

MR. T. MICHAEL MAY
PRESIDENT AND CEO
HAWAIIAN ELECTRIC CO INC
PO BOX 2750
HONOLULU, HI 96840-0001

Payment Due on or before 5/1/2007
(Interest charges will accrue after due date)

Description	Total
2007 Membership Dues for 1st Quarter:	
Regular Activities of Edison Electric Institute[1]	$95,281
Industry Structure Assessment[2]	9,528
Mutual Assistance Program[3]	1,250
Total	$ 106,059

[1] Pursuant to OBRA, the portion of membership dues allocable during 2007 relating to influencing legislation not deductible for Federal Income Tax purposes is estimated to be 20%.

[2] The portion of the voluntary Industry Structure Assessment allocable during 2007 relating to influencing legislation is estimated to be 40%.

[3] Voluntary assessment approved by EEI Executive Committee relating to improvements for the rapid response to disasters. No portion of this assessment is allocable to influencing legislation.

PLEASE NOTE INFORMATION FOR WIRING.

The following is instruction for transferring funds electronically to Edison Electric Institute's account at the Wachovia Bank N.A. in Washington, DC:

Beneficiary's Bank:	**Wachovia Bank, N.A.**
Bank's Address:	**Washington, DC**
Bank's ABA Number:	**0 5 4 0 0 1 2 2 0**
Beneficiary:	**Edison Electric Institute**
Beneficiary's Acct No:	**2 0 0 0 0 1 3 8 4 2 8 9 7**
Beneficiary's Address:	**701 Pennsylvania Avenue, NW Washington, DC 20004-2696 USA**
Beneficiary Reference:	**2007 Membership Dues**

Please refer any questions to Ed Milad at: phone-(202) 508-5430; fax-(202) 508-5030; *or* e-mail-emilad@eei.org.

EEI EDISON ELECTRIC INSTITUTE

701 PENNSYLVANIA AVENUE, NW
WASHINGTON, DC 20004-2696
PHONE (202) 508-5000

INVOICE FOR MEMBERSHIP DUES
REMITTANCE COPY

Date	Invoice Number
03/26/2007	1-000050682

MR. T. MICHAEL MAY
PRESIDENT AND CEO
HAWAIIAN ELECTRIC CO INC
PO BOX 2750
HONOLULU, HI 96840-0001

Payment Due on or before 7/1/2007
(Interest charges will accrue after due date)

Description	Total
2007 Membership Dues for 2nd Quarter:	
Regular Activities of Edison Electric Institute[1]	$ 95,281
Industry Structure Assessment[2]	9,528
Mutual Assistance Program[3]	1,250
Total	$ 106,059

[1] Pursuant to OBRA, the portion of membership dues allocable during 2007 relating to influencing legislation not deductible for Federal Income Tax purposes is estimated to be 20%.

[2] The portion of the voluntary Industry Structure Assessment allocable during 2007 relating to influencing legislation is estimated to be 40%.

[3] Voluntary assessment approved by EEI Executive Committee relating to improvements for the rapid response to disasters. No portion of this assessment is allocable to influencing legislation.

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Bank's Address:	**Washington, DC**
Bank's ABA Number:	**0 5 4 0 0 1 2 2 0**
Beneficiary:	**Edison Electric Institute**
Beneficiary's Acct No:	**2 0 0 0 0 1 3 8 4 2 8 9 7**
Beneficiary's Address:	**701 Pennsylvania Avenue, NW Washington, DC 20004-2696 USA**
Beneficiary Reference:	**2007 Membership Dues**

Please refer any questions to Ed Milad at: phone-(202) 508-5430; fax-(202) 508-5030; *or* e-mail-emilad@eei.org.

EDISON ELECTRIC INSTITUTE

INVOICE FOR MEMBERSHIP DUES

701 PENNSYLVANIA AVENUE, NW
WASHINGTON, DC 20004-2696
PHONE (202) 508-5000

Date	Invoice Number
03/26/2007	1-000050682

MR. T. MICHAEL MAY
PRESIDENT AND CEO
HAWAIIAN ELECTRIC CO INC
PO BOX 2750
HONOLULU, HI 96840-0001

Payment Due on or before 10/1/2007
(Interest charges will accrue after due date)

Description	Total
2007 Membership Dues for 3rd Quarter:	
Regular Activities of Edison Electric Institute[1]	$95,281
Industry Structure Assessment[2]	9,528
Mutual Assistance Program[3]	1,250
Total	$ 106,059

[1] Pursuant to OBRA, the portion of membership dues allocable during 2007 relating to influencing legislation not deductible for Federal Income Tax purposes is estimated to be 20%.

[2] The portion of the voluntary Industry Structure Assessment allocable during 2007 relating to influencing legislation is estimated to be 40%.

[3] Voluntary assessment approved by EEI Executive Committee relating to improvements for the rapid response to disasters. No portion of this assessment is allocable to influencing legislation.

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Bank's Address:	**Washington, DC**
Bank's ABA Number:	**0 5 4 0 0 1 2 2 0**
Beneficiary:	**Edison Electric Institute**
Beneficiary's Acct No:	**2 0 0 0 0 1 3 8 4 2 8 9 7**
Beneficiary's Address:	**701 Pennsylvania Avenue, NW Washington, DC 20004-2696 USA**
Beneficiary Reference:	**2007 Membership Dues**

Please refer any questions to Ed Milad at: phone-(202) 508-5430; fax-(202) 508-5030; *or* e-mail-emilad@eei.org.

EEI EDISON ELECTRIC INSTITUTE

INVOICE FOR MEMBERSHIP DUES

701 PENNSYLVANIA AVENUE, NW
WASHINGTON, DC 20004-2696
PHONE (202) 508-5000

Date	Invoice Number
03/26/2007	1-000050682

MR. T. MICHAEL MAY
PRESIDENT AND CEO
HAWAIIAN ELECTRIC CO INC
PO BOX 2750
HONOLULU, HI 96840-0001

Payment Due on or before 12/1/2007
(Interest charges will accrue after due date)

Description	Total
2007 Membership Dues for 4th Quarter:	
Regular Activities of Edison Electric Institute[1]	$95,281
Industry Structure Assessment[2]	9,528
Mutual Assistance Program[3]	1,250
Total	$ 106,059

[1] Pursuant to OBRA, the portion of membership dues allocable during 2007 relating to influencing legislation not deductible for Federal Income Tax purposes is estimated to be 20%.

[2] The portion of the voluntary Industry Structure Assessment allocable during 2007 relating to influencing legislation is estimated to be 40%.

[3] Voluntary assessment approved by EEI Executive Committee relating to improvements for the rapid response to disasters. No portion of this assessment is allocable to influencing legislation.

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Bank's Address:	**Washington, DC**
Bank's ABA Number:	**0 5 4 0 0 1 2 2 0**
Beneficiary:	**Edison Electric Institute**
Beneficiary's Acct No:	**2 0 0 0 0 1 3 8 4 2 8 9 7**
Beneficiary's Address:	**701 Pennsylvania Avenue, NW** **Washington, DC 20004-2696 USA**
Beneficiary Reference:	**2007 Membership Dues**

Please refer any questions to Ed Milad at: phone-(202) 508-5430; fax-(202) 508-5030; *or* e-mail-emilad@eei.org.

DOD-IR-128

Ref: Outside services general. Refer to the response to CA-IR-372

a. This response at page 2 of 5 states: "This higher level of political and community involvement requires a 2007 test year estimate of $660,000." Please identify how much of the $660,000 relates to the higher level of political involvement.
b. Refer to page 2 of the response. Provide the information related to the proposed wind farm at Kahe.
c. Refer to page 2 of the response. Provide the information related to understanding the viewpoint of the communities located in the West Oahu/Waianae area.
d. Refer to page 2 of the response. Provide the information related to developing a community based wind education program.
e. Refer to page 4. Explain fully why the outside consulting services related to coordination of speakers bureau engagements etc., with an emphasis on energy conservation and efficiency measures are not charged to a DSM program.
f. Refer to page 5 of the response. Provide the information related to the potential to develop pumped hydro-storage projects.
g. Refer to page 5 of the response. Provide the information related to the potential Kahaku [sic] area wind farm.
h. Refer to page 5 of the response. Provide the information related to the resource conservation education program for the West Oahu community.
i. Provide the invoices for the $160,000 (page 2 of 5), the $124,000 (page 3 of 5), the $172,000 (page 3 of 5) the $49,000 (page 4 of 5), the $63,000 (page 4 of 5), and the $21,000 (page 5 of 5).

HECO Response:

a. The term "political" as used (Hawaiian Electric's response to CA-IR-372, Page 2 of 5) in this context is synonymous with "community". Hawaiian Electric does not make partisan political contributions or engage in partisan political actions on Company time or with Company funds. To the extent that this particular information request took the use of the word "political" to indicate such a use of funds, the response is zero.

b. In December 2003, Hawaiian Electric met with Waianae and Honouliuli area residents to discuss the possibility of developing the wind resource in the upper area of the Kahe Power Plant and obtained their approval to conduct meteorological testing to verify earlier wind mapping findings. After the collection of twelve months of wind data, the Company met with the same area representatives in May 2005 to share the test results that verified that a utility-scale wind farm was viable. Subsequently, the Company held three public meetings in the West Oahu area to share its findings and solicit feedback on a potential wind farm project at Kahe. At the meetings, the Company informed the community on wind energy, the benefits and impact; and elicited and collected public input and comments on the issue of establishing a wind farm on the ridges above Kahe Point. Over two hundred people attended these meetings which were held in July, 2005. Two of the Company's consultants who are retained on an on-going basis, and have the expertise and relationships with the West Oahu communities assisted the Company in the coordination of these meetings with the public.

c. This particular consultant's expertise among other things, includes his understanding of and relationships with the communities and leaders in the West Oahu/Waianae area on cultural and environmental issues. This consultant is a long-time community activist and leader who has substantial expertise in the grass roots community process, particularly in the rural areas of Oahu. He also has substantial experience and expertise in working with the Native Hawaiian community. The West Oahu/Waianae communities differ from the rest of Oahu in several ways as they are host to a number of community infrastructure burdens and impacts relative to the rest of Oahu. The communities have been and are host to municipal landfills and dumps located in Waianae Valley and then in Nanakuli since the early 1900's. The only municipal landfill currently in operation for the entire island is located in their community at Waimanalo Gulch. Power plants (operated by both Hawaiian Electric and independent power producers) which service the entire island are also located in their communities at Kahe and Campbell Industrial Park. Nanakuli, a community in West Oahu, is home to the single largest Native Hawaiian community in the world. The West Oahu area has been economically depressed for decades and has experienced its challenges of low educational achievement levels, high levels of crime, drug use, and incarceration. The West Oahu area also houses the state's single largest homeless population.

d. A community based wind education program came about through the Company's discussions with community leaders in 2003, when it first approached the community on conducting meteorological testing for a potential wind farm in Kahe. One of the conditions set forth by the community in going forth with the testing was to execute a wind energy education campaign for the residents of the West Oahu/Waianae coast. The site chosen for the potential wind farm at Kahe, was, and is still viewed as sacred land by numerous Native Hawaiians of the area, housing sacred sites and potential burial grounds. Accordingly, in light of this condition, and the pre-existing knowledge of winds of the area by the Native Hawaiian community, special and significant work had to be done to ensure that a community-based wind energy program adequately reflected the Native Hawaiian perspective on wind and the history of the area. This particular consultant worked with area high school media program leaders and students to develop a student video on wind energy and worked with students and area elders and cultural specialists to develop a Native Hawaiian culture based wind energy education display and packet. The final product was aired on public television and the display and videos were presented at community venues and events. This consultant is a long-time community activist and leader who has substantial expertise in the grass roots community process, particularly in the rural areas of Oahu. He also has substantial experience and expertise in working with the Native Hawaiian community.

e. The speakers' bureau presentations are overviews which discuss a range of solutions needed to meet Hawaii's energy needs. Each presentation is customized with a different emphasis for its audience. Although there is always some discussion on encouraging energy conservation and efficiency and the key role that managing demand plays in meeting future energy needs, the presentation is not designed to primarily be an informational session on individual DSM programs. Examples of energy conservation and efficiency measures are discussed, along with other energy strategies (renewable energy, central station and distributed generation) that must be pursued to meet future energy needs. Additional information on a variety of Hawaiian Electric conservation, energy efficiency and load control programs is made available, again depending on the interests of the audience.

f. Pumped hydro-storage projects have the potential to increase the use of renewable energy for Hawaiian Electric. The Company is aware that such a facility on the island will alter the Oahu landscape and could have significant impacts to Native Hawaiian culture resources, sacred areas and gathering rights. This particular consultant assisted the Company in gathering information on potential cultural and environmental concerns to better understand the issues that could possibly arise in having a pumped hydro-storage facility on the island. This consultant is a long-time community activist and leader who has substantial expertise in the grass roots community process, particularly in the rural areas of Oahu. He also has substantial experience and expertise in working with the Native Hawaiian community.

g. The Kahuku area on the island of Oahu has been identified as a potential area for wind farms. This particular area is abundant in archaeological and cultural resources. The

Company's consultant assisted the Company in identifying Native Hawaiians who had knowledge of the Kahuku area and who might be able to provide information on sacred areas, burials, and cultural resources within the proposed project areas. This consultant is a long-time community activist and leader who has substantial expertise in the grass roots community process, particularly in the rural areas of Oahu. He also has substantial experience and expertise in working with the Native Hawaiian community.

h. This particular consultant worked with key community leaders to build a community based conservation education program for the West Oahu and Waianae Coast communities. The program is designed to instill and advance a conservation ethic in Hawaii's community. Energy conservation as well as the conservation of water, land, and other natural resources is the focus. A key component of the program is on the West Oahu Schools. This consultant is a long-time community activist and leader who has substantial expertise in the grass roots community process, particularly in the rural areas of Oahu. He also has substantial experience and expertise in working with the Native Hawaiian community.

i. Without waiving the objection stated below, and pursuant to Amended Protective Order No. 23378 filed June 4, 2007, the Company provides as Attachment 1, a listing of the requested invoices, which discloses the consultants'name and transaction amount. The invoices are also available for review at Hawaiian Electric's Regulatory Affairs office; please contact Dean Matsuura at 543-4622 to arrange a time to review such documents. Hawaiian Electric objects to providing the requested documents as they contain confidential, commercially sensitive consultant information (e.g., charges associated with the particular supplier) and are voluminous.

Confidential Information
Deleted Pursuant To
Amended Protective Order No. 23378

DOD-IR-128
DOCKET NO. 2006-0386
ATTACHMENT 1
PAGES 1-3 OF 3

Attachment 1 contains confidential information and is being provided subject to Amended Protective Order No. 23378, dated June 4, 2007.

DOD-IR-129

Refer to the response to CA-IR-373.

a. Does HECO record any donations or charitable contributions in below-the-line accounts, such as Account 426? If not, explain fully why not.

b. Please refer to pages 3-6 of 6 of the response and explain in detail how HECO distinguishes the types of payments to the various groups and organizations under the banner of "Community Process" from donations and charitable contributions recorded in Account 426.

<u>HECO Response:</u>

a. Yes.

b. Expenditures to support the "Community Process" are limited to the four areas as described in Hawaiian Electric's response to CA-IR-373(b), and to groups and organizations that support education, environment, culture, health, social welfare and the military. Contributions recorded in Account 426 are not limited to these areas of interest.

In today's environment, the challenge for Hawaiian Electric is the unpopularity of any proposed new infrastructure (especially power generating facilities) as well as much of its existing infrastructure. Communities have expressed that when they bear the burden of these facilities which serve all customers island-wide, they would like acknowledgement of that burden. Furthermore, they have made clear that they expect to have a role in defining the form of that acknowledgement.

From a ratepayer point of view, Hawaiian Electric's efforts to support this community process are an extraordinarily sound investment in minimizing dispute and litigation and the resulting costs that can add to a project, and allowing necessary system reliability improvements to occur in a timely manner. The opposite scenario is what Hawaiian Electric experienced with the Wa'ahila Ridge transmission proposal and HELCO with the Keahole Power Plant expansion, where the costs of dispute and delay exceeded the Company's proposed community process budget many times over.

It's true it can be easier to justify the costs of handling an existing project challenge (it exists and the Company can "prove" it) than to justify the costs of prevention (one can rationalize that the problem may never occur and question whether the Company can "prove" it has a problem). At the same time, it is also clear that preventing such challenges facilitates timely implementation and can ultimately cost customers much less than addressing the challenge once it blows up into a real problem.

DOD-IR-130

Refer to the response to CA-IR-376.

a. Have all expenses related to “restricted stock” and stock based compensation, stock options, and incentive compensation been removed from test year operating expenses in HECO’s June 2007 update?

b. If the answer to part a is negative, please identify, quantify (showing the amounts remaining in each account) and explain all remaining amounts for “restricted stock,” stock options, and incentive compensation and other forms of stock based compensation.

HECO Response:

a. Yes, all restricted stock and stock based compensation, stock options, and incentive compensation have been removed from the estimates reflected in HECO T-10’s updates.

b. N/A

DOD-IR-131

Ref: Refer to CA-IR-379.

a. What is HECO's definition of "Oncost."

b. Why shouldn't the three non-recurring O&M projects identified in the response to CA-IR-379b be removed, since they have been identified as non-recurring? Explain fully why HECO has not removed these.

HECO Response:

a. "On-costs" is the Ellipse terminology for overheads. See Ms. P. Nanbu's direct testimony (T-10), beginning page 23, line 18, through page 27, line 2.

b. These three non-recurring O&M projects are included in the 2007 test year since they are expected to be completed in 2007. However, as noted on page 10 of Mr. B. Tamashiro's (T-13) June 2007 Update (revised HECO-1306), a normalization adjustment was made to the non-recurring O&M projects' costs in order to provide a more reasonable estimate of what is anticipated to be incurred in the next several years.

DOD-IR-132

Ref: Refer to CA-IR-392.

a. Please confirm that the $91,544 for the Ellipse Migration project plant add estimate should be removed from plant rate base. If this cannot be confirmed, explain fully why not.

b. Please confirm that the error relating to removal of the $91,544 for the Ellipse Migration project was discovered too late to be reflected in HECO's June 2007 update, and is not reflected in HECO's June 2007 update. If this cannot be confirmed, explain fully why not.

c. Page 2 of Attachment 1 to the response indicates that: "By starting the work in 2007 we plan to finish the work in 2008." Please break out the $509,000 of O&M expense estimated for Account 921 and the remaining $316,044 between (1) 2007 and (2) 2008.

d. How do the amounts reflected in the 2007 by HECO relate to the amounts listed on page 6 of Attachment 1. Please identify, quantify and explain each reconciling item.

HECO Response:

a. Yes. The $91,544 for the Ellipse Migration plant addition estimate should be removed from the 2007 plant rate base.

b. Yes. The error relating to removal of the $91,544 for the Ellipse Migration project was discovered too late, and therefore was not reflected in HECO's June 2007 update. However, the HECO T-16 June 2007 Update will be revised shortly and will include the impact of the excess $91,544 associated with this project in the test year plant additions.

c. A breakdown of the $509,000 of O&M can be found in CA-IR-133(c). However, as mentioned in the response to CA-IR-133, subsequent to filing the rate case budget, HECO conducted a more detailed review of the project requirements and modified the estimated cost for 2007 to $990,000 for the operating budget. In January 2007, HECO contracted with the vendor Mincom to conduct a detailed Ellipse Unix Migration scoping study. Based on the information learned from this study, HECO updated the project estimate and internally requested authorization to commit and spend funds in March 2007. This PIF authorization is document CA-IR-392, Attachment 1. Referencing page 6 of CA-IR-392 Attachment 1, HECO estimated spending $854,000 ($51,171 + $505,785 + $297,260) of O&M non labor costs and $314,555 ($280,727 + $33,828) of capital expenditure costs (and plant additions) in 2007. Note that the difference between the $314,555 of capital costs for 2007 shown on CA-IR-392 Attachment 1, and the $316,044 provided in the HECO June 2007 update of plant additions is primarily due to the difference in the on-costs rates used when the estimates were prepared. (As noted in the response to CA-IR-438, HECO will be revising HECO T-10's June 2007 Update filed June 27, 2006, to reflect $854,000 for Ellipse Unix migration non-labor O&M costs for the test year.) In 2008, HECO will spend an estimated $319,818 ($4,931+$280,915 + $33,972) of nonlabor O&M costs and $143,437 ($13,229 + $130,208) of capital expenditure costs (and plant additions) for the Ellipse Unix migration project. Note that capital costs for hardware required for testing and development will be purchased and placed into service in 2007, and additional hardware will be acquired when conversion is implemented in 2008.

d. See response to item c.